Submission Annex

ET.12 – Uncertainty mechanisms

December 2019

As a part of the NGET Business Plan Submission

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Executive summary

The energy industry is going through its biggest change in a generation and the associated uncertainty is considerable. Meeting the government's net-zero legislated target at lowest cost to consumers requires us to have a suite of mechanisms that deal with cost and volume uncertainty whilst allowing us to maintain the strong efficiency incentive of an ex-ante price control.

For the T2 period we propose 21 Uncertainty Mechanisms (*excluding financial indexation and cost pass-through*) associated with our business plan submission, as shown in table 1. Our proposals cover a cost uncertainty range across three areas relative to our baseline proposals (1) supply & demand uncertainty (*£729m- £1994m of associated cost uncertainty*); (2) whole systems uncertainty (*>£700m of associated cost uncertainty*); and (3) externally driven uncertainty (*>£750m of associated cost uncertainty*). In practise the cost uncertainty range could change once expenditure on in-period determinations which will only emerge in the T2 period are included.

Each of our proposals has been rigorously and robustly justified. We have extensively reviewed T1 period Uncertainty Mechanism performance, the uncertainty landscape for the T2 period, and feedback from our stakeholders. A comprehensive analytical framework, balancing complexity and cost reflectivity has been employed, using techniques such as regression analysis and Monte Carlo testing where we propose volume driver mechanisms to ensure the underlying Unit Cost Allowances are cost reflective.

This annex does not cover the cross-sector Uncertainty Mechanism for financial indexation and cost pass through. Full coverage of our proposals on these can be found in Chapter 15 "*How our plan should be financed*" of our submission, annex A14.14 "*RPEs and ongoing efficiency*", and annex A15.01 "*We can finance our plan*".

Table 1- Summary of our proposed Uncertainty Mechanisms for the T2 period

Area	Proposed UM			Adjusts allowances for …
Supply and demand uncertainty	Boundary capability	Volume drivers	Existing	changes in boundary capacity
	Generation connections		Existing	changes in generation connections
	Demand connections		Existing	changes in demand connections
	Facilitate competition (pre-consents)		New	delivery of contestable works consents
Whole systems uncertainty	System operability (voltage)		New	delivery of new shunt reactors
	Low voltage substation re-build		New	impact of embedded generation
	Protection and control	In-period determinations	New	needed protection and control upgrades
	Harmonic filters		New	delivery of filters for customers
	Whole systems coordinated adjustment mechanism		New	efficient whole system solutions
	System operability (other ESO requirements)		New	changes required by the ESO
Externally driven uncertainty	Physical security		Existing	changes in industry requirements
	Visual Impact Provision		Existing	delivering VIP projects when agreed
	Extreme weather		New	changes in requirements
	Operational Technology (OT) Cyber security		New	changes in cyber requirements (OT)
	Information Technology (IT) Cyber security		New	changes in cyber requirements (IT)
	Black start		New	changes in BEIS' requirements
	Ensuring a resilient network		New	new threats that arise
	SF_6 replacement programme		New	delivering SF_6 reduction investments
	Urban Improvement Provision		New	projects in disadvantaged urban areas
	Net Zero Provision		New	projects to deliver net-zero policy
	Innovation Plan		New	update our innovation programme

Contents

1.0 Introduction

In the May 2019 Sector Specific Consultation Ofgem indicated the continued need for Uncertainty Mechanisms (**UMs**) in an ex-ante price control*: "There is a forecast risk that we provide expenditure allowances that are higher or lower than they actually need to be. We use a range of uncertainty mechanisms to manage this risk."*

The transformation in the energy industry will increase the likelihood of customer needs changing in the T2 period, despite the shorter price control timeframe. This is likely to be further increased by the move towards whole system planning as a greater range of solutions become available through new processes like an expanded Network Options Assessment (**NOA**), being undertaken by the Electricity System Operator (**ESO**) and by further legislative and policy changes linked to delivering net-zero carbon emissions by 2050.

In line with Ofgem's guidance we have developed our baseline business plan to be consistent with the low-end of the industry's Common Energy Scenario. We believe that this provides a consistent, but conservative view of potential customer activities across the T2 period. Ofgem also require that we demonstrate how our plan can facilitate net-zero by 2050. UMs are the key tool through which our allowances can flex to meet this target.

UMs are not new for the T2 period. In the T1 period our load related UMs (*excluding the mid-period review*) have saved consumers £768m by automatically decreasing our allowances in response to evolving market conditions.

In preparing our T2 period plans, we have engaged with a range of stakeholders to discuss the causes and effects of uncertainty, the role UMs played in T1 period, and their views on our approach to managing uncertainty in the T2 period. This engagement showed strong support for the continued use of UMs, but a need to refine them to be fit for purpose. There was also support for the expansion of UMs, designed to manage uncertainty in areas of our plan where whole system options and competition provide opportunities to minimise the cost of the energy transition for consumers.

This annex contains details of our proposals for bespoke UMs in our business plan submission. These mechanisms are unique to National Grid Electricity Transmission (**NGET**), and therefore not set out within the May 2019 Sector Specific Methodology Decision (**SSMD**) but have been developed in parallel with extensive Ofgem and stakeholder engagement. This annex also contains our proposals for cross-sector mechanisms related to physical and cyber security, and whole systems coordination, proposed by Ofgem in the SSMD.

This annex does not cover the cross-sector UMs for financial indexation and cost pass through. Full coverage of our proposals on these can be found Chapter 15 "*How our plan should be financed*" of our submission, annex A14.14 "*RPEs and ongoing efficiency*", and annex A15.01 "*We can finance our plan*".

Uncertainty in the T2 period ranges across three areas:

1. **Supply and demand uncertainty** – changes to customers connecting to the system, and resulting wider flows across networks;
2. **Whole systems uncertainty** – uncertainty generated by maintaining the option to identify and deploy whole system alternatives to meet system requirements at lower cost to consumers
3. **Externally driven uncertainty** – uncertainty related to changes in legislation, policy or technological advances currently unknown and which may emerge during the T2 period

The types of mechanisms we propose to manage uncertainty across these three areas align with those proposed by Ofgem in the December 2018 Sector Specific Consultation:

1. **Volume drivers:** used when the volumes of activity that might be required is uncertain;
2. **In-period determinations:** used when the need and scope of projects is uncertain;
3. **Indexation:** used when the evolution of prices is uncertain; and
4. **Cost pass-through:** used for costs that are outside network company control

How Uncertainty Mechanisms covered by this annex work in practise

Volume drivers adjust our baseline allowance up and down by a Unit Cost Allowance (**UCA**) to ensure consumers only pay for what our customers need us to deliver. The adjustment is automatic, based on the actual volumes of pre-defined “output”, such as the amount of new generation capacity connected to our network in each year of the price control. Volume drivers are used when there is relative cost certainty, but volume uncertainty exists.

In-period determinations require a separate funding application to be submitted, reviewed and approved by Ofgem before our baseline allowance is adjusted. This reduces the risk for consumers when there is uncertainty around both costs and volumes.

The proposals in this annex are underpinned by rigorous analysis and consideration of a range of alternative options. Throughout the development process we have constantly challenged ourselves to find a better way for consumers, customers and stakeholders. Inevitably this requires a trade-off to strike the right balance between design complexity and cost reflectiveness.

We have structured the main body of this annex into four sections:

1. What we have learned from the T1 period UMs to shape our T2 period proposals
2. The uncertainty landscape in the T2 period
3. Our approach to designing rigorous and comprehensive proposals
4. Our proposals on a page

Accompanying this, we are also supplying the following material:

A. **Three detailed appendices**, explaining our analytical framework, data sources and detailed justification of our proposals in line with Ofgem’s Business Plan Guidance
B. **Excel workbooks** for four of our more complex volume driver UMs (*generation, demand, boundary capability, and system operability (voltage)*) which contain our full data set and a step-by-step guide to our analysis

2.0 What we have learned from the T1 period to shape our T2 period proposals

Chapter key messages	
	▪ The industry has changed significantly over the T1 period ▪ UCAs generally worked well, but haven't fully kept pace with change ▪ Our stakeholders have signalled UMs need to evolve for the T2 period

In the T1 period, we had 9 UMs, listed in table 2. All these UMs, except for DNO mitigation, have been used extensively. Additionally, we had a mid-period review in 2016/17 which provided the opportunity to examine specific aspects of our baseline allowance and propose adjustments to reflect updates to the environment in which we operate.

2.1 The industry has changed significantly over the T1 period

Conceptually UMs have worked well for consumers in the T1 period. Our load related UMs (*including the mid-period review*) have saved consumers £768m in response to evolving market conditions. Figure 1 highlights how allowances have adjusted for the three largest volume driver mechanisms (1) Generation connections; (2) Demand connections; and (3) Boundary capability.

Table 2 – T1 period UMs

UM	Type	Description
Generation connections	Volume driver	▪ Baseline allowance, plus: ▪ £/kW allowance for a new connection ▪ £/km OHL allowance based on 2012 IET report
Demand connections		▪ Baseline allowance, plus: ▪ £/SGT allowance for a connection ▪ £/km OHL allowance based on 2012 IET report
Boundary capability		▪ Baseline allowance, plus: ▪ £/MW allowance specific to each boundary
DNO mitigation		▪ Baseline allowance, plus: ▪ £/unit specific to asst type
Embedded generation		▪ No baseline allowance ▪ £/kW allowance per new connection ▪ Only applicable in two zones (North East and Mid-Wales)

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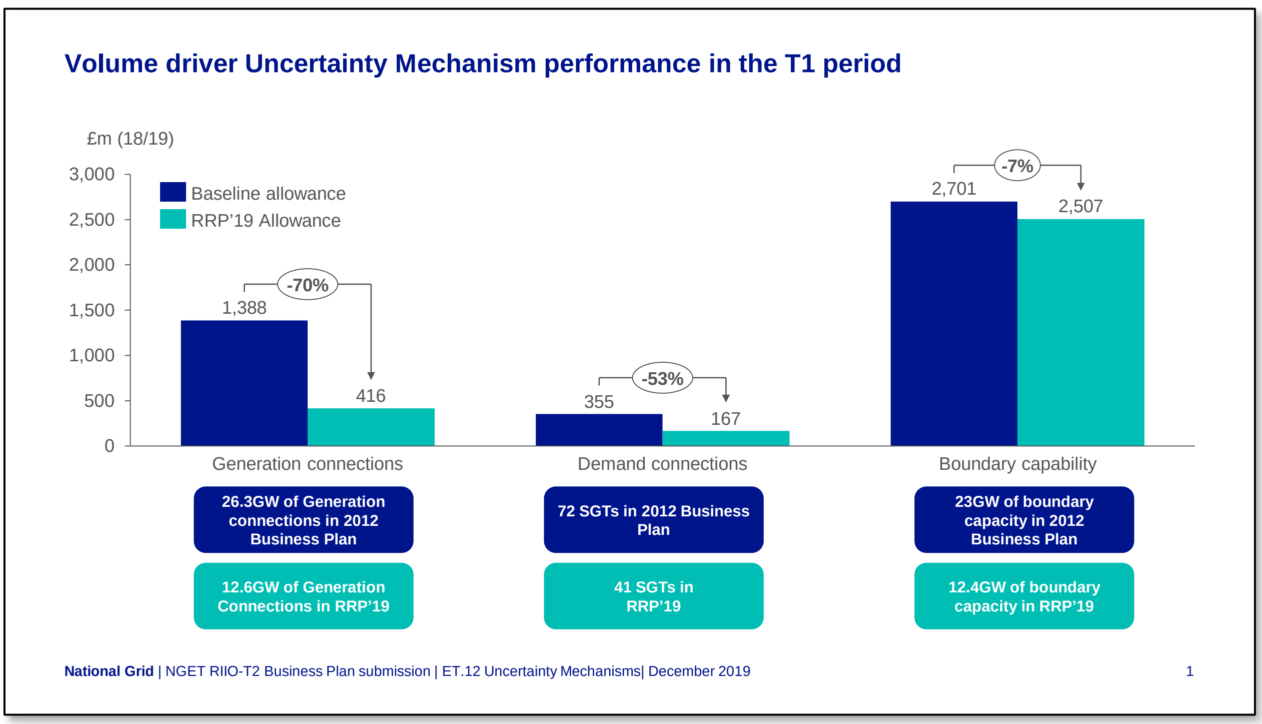
Undergrounding		▪ No baseline allowance ▪ £/km for cable undergrounding based on 2012 IET report ▪ Applicable all categories of work
Strategic wider works		▪ Baseline only for pre-construction works ▪ For wider works providing boundary capability over £500m ▪ Specific examination of need case and spend efficiency
Visual Impact Provision	In-period determination	▪ No baseline allowance ▪ Submissions to draw from a £500m shared allowance between network companies
Physical security		▪ No baseline allowance ▪ Two determinations, one 2015 and 2018 to reflect updated industry guidance

***OHL**: Overhead Line; **IET**: Institute of Engineering and Technology; **SGT**: Supper Grid Transformer*

Figure 1 – T1 period allowance adjustment for the three largest volume driver UMs (*Regulatory Reporting Period (RRP) 2019*)



Allowances have been adjusted for **generation connections** as shown in figure 1, as some projects have delayed connection, such as offshore wind farms. Additionally, several nuclear connections terminated their contracts (*e.g. Horizon*). Several projects contracted at the start of the T1 period have also been unsuccessful in the capacity market, leading to contract terminations and delays. In addition, the decentralisation trend has gathered pace with higher volumes of generators connecting onto the distribution system.

Decentralisation has also been a contributor to the 53% decline in number of Super Grid Transformers (**SGT**) we have connected for **demand customers** in the T2 period. As embedded generation has grown the volume of demand flowing onto the distribution network from the transmission network has declined and, in some area, this flow has reversed. Additionally, through taking a whole systems approach to planning the system, we have been able to defer and replace some transmission network investment with non-build Distribution Network Operator (**DNO**) solutions, such as Active Network Management (**ANM**) schemes.

Boundary capability requirements have been impacted by the changing nature of generation and demand connections, with some planned boundary reinforcements being deferred or cancelled. The introduction of the ESO's NOA process during the T1 period has also resulted in an annual economic assessment and recommendation for within period wider system needs and the introduction of new system boundaries, without allowance has brought greater volatility.

Beyond generation, demand and boundary works we have an **embedded generation** UM (*not shown in figure 1 given it had a zero baseline*) which gave a [redacted]£/kW UCA linked to the growth in embedded generation in two regions Mid-Wales & North East. A total additional funding allowance of £32m *(2018/19 prices)* was provided through this mechanism.

The T1 period has also seen shifts in the external political and societal environment in which network companies operate. Rightly, there has been greater focus on protecting our network from external threats, and on the impact our assets have on local communities.

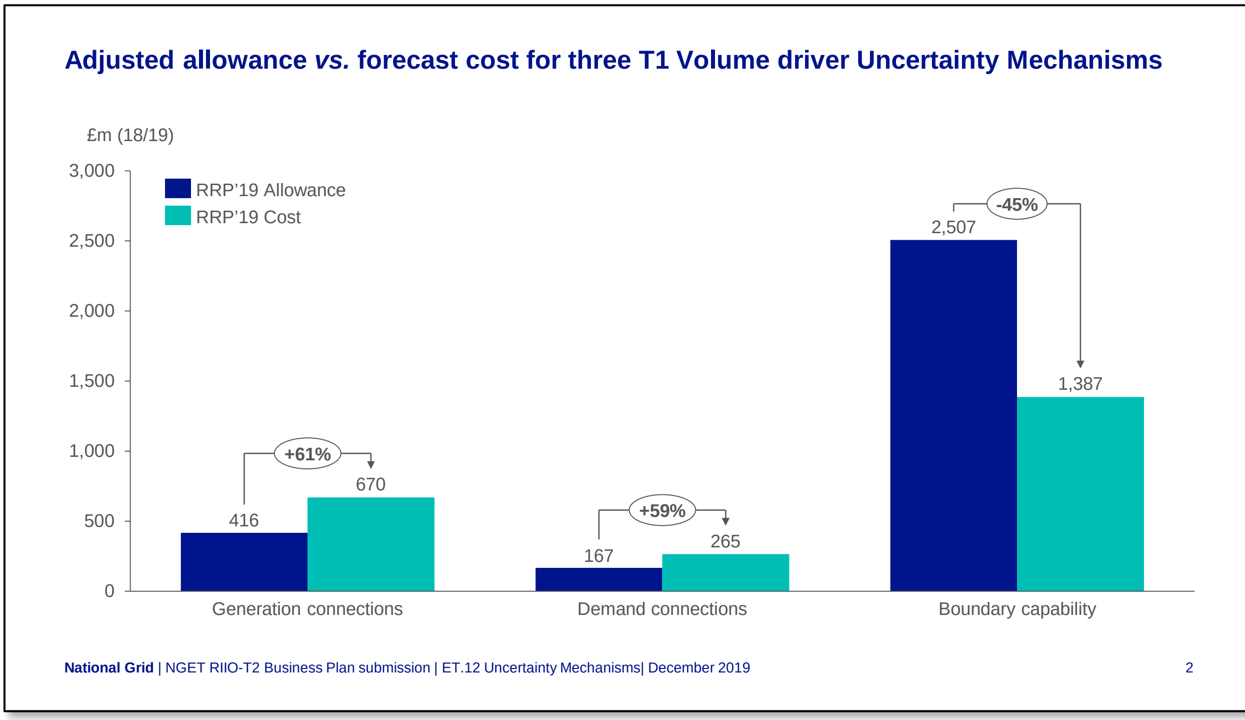
Two of the in-period determinations in table 2 have been used: **Visual Impact Provision** and **Physical security**. Both had a zero-baseline allowance. For Visual Impact Provision stakeholders have decided we should deploy ~£100m for land scape enhancement in Dorset. We anticipate requesting additional allowances in Peak East and Snowdonia before closing out the T1 period to deliver undergrounding investments selected by the Stakeholder Advisory Group. On Physical security through a 2015 in-period determination, an additional ~£300m in funding was provided, although we returned ~£70m to consumers through a 2018 determination for works no longer required. This is an example of better information on requirements becoming available through working with stakeholders on a sensitive area of investment.

One **Strategic Wider Works** submission has been made to Ofgem for Hinkley-Seabank and granting of allowances is still under consideration by Ofgem.

2.2 UCAs generally worked well, but haven't fully kept pace with change

Whilst UMs have been effective in the T1 period, adjusting allowances to external factors, the associated UCAs have not fully kept pace with the changing types of customers we are connecting and the types of work we are delivering. UM designs for the T1 period where also overly simplistic to cover the inherently complex nature of the system and market effectively. Figure 2 shows how adjusted allowances compare to forecast costs for the three largest UMs from the T1 period: generation, demand and boundary capability.

Figure 2 – T1 period adjusted allowance vs. forecast cost for the three largest volume driver UMs (*Regulatory Reporting Period 2019*)



For **generation connections** the types of customer we are facilitating is changing. The volume of smaller connections requesting contracts has increased. Customers are creating a need to do enabling works which were less common before the T1 period, such as thermal enhancement of the existing circuits beyond substation works. We forecast our costs will be 61% higher than the adjusted allowance.

Demand connections also have new types of directly connected customers requesting connections, such as data centres. The simple design of UCA based on number of SGTs required for a DNO or network rail customer has led to a poor representation of actual costs as many connections with a scope other than a 'basic' transformer installation are being requested. This has meant that customers requiring new connection bays at existing infrastructure sites (*where no SGT is needed*) has not triggered funding through the UCA, even though spend for installation for the new bays is required. We forecast our costs will be 59% higher than the adjusted allowance. These types of connection requests are likely to become more common in the T2 period as the nature of DNO networks and customers change.

For **boundary capability** the background we are delivering against has changed since the start of the T1 period, with higher volumes of interconnection and embedded PV generation especially in southern England. This has meant that some reinforcements like reconductoring the Kemsley-Littlebrook and Fleet- Lovedean circuits, have delivered more capability than envisaged when the

T1 period UM was designed. We are also delivering innovative technologies like power flow controllers which give higher capability for lower cost, demonstrating the benefits of ex-ante allowances to deliver benefits. Allowances for each boundary were built by summing up the cost of works on the boundary required to meet the scenario used to set our T1 period baseline plan (*Gone Green*) and dividing by the capacity delivered. In many cases the allowance was built from a narrow set of works (*e.g. two projects per boundary in some cases*) and meant the UCA was not sufficiently cost reflective of the different types of investment that have subsequently been undertaken on some boundaries. Due to a combination of lower cost through innovation and a UCA that was insufficiently cost reflective we forecast our costs will be 45% lower than the adjusted allowance.

2.3 Our stakeholders have signalled UMs need to evolve in the T2 period

Understanding stakeholder needs and acting on their requirements has been central to our approach across our business plan submission. Our engagement approach on UMs has been proportionate, targeted predominately on stakeholders who are most impacted and interested in this aspect of our plan.

We published a consultation document in February 2019 supported by a webinar and other bespoke engagements (*e.g. through EnergyUK and bilaterally with DNOs*), where stakeholders told us it is appropriate to review existing UMs and consider the introduction of new ones, particularly where these facilitate potential whole system solutions.

Our **Independent Stakeholder Group** also challenged our approach to UMs and whether we are doing enough to ensure the price control is sufficiently flexible to allow net-zero 2050 targets to be met They also told us we could adopt a "*braver*" approach to addressing SF_6 leakage through innovation and leading by example to generate innovation in the supply chain. We were also challenged on whether our plans are doing enough to support system operability into the future. Feedback which was later echoed by both the **RIIO-2 Challenge Group** ("*we are particularly interested in your plans to support the ESO in its goal of carbon-free operation by 2025…*") and in the **ESO's direct feedback** on our July draft plan ("*keen to see you thinking more broadly around stability issues and what solutions you could provide*").

DNOs signalled through bilateral engagements they are keen to ensure the ability to identify and deliver whole systems solutions remained within the price control period and that UMs where a solution to facilitate this.

More broadly we have **engaged directly with consumers** on our plans in several areas. For example, when asked 60% of 1000 consumers surveyed said we should be net-zero by 2030 or 2040, ahead of the government target.

We have **engaged directly with Ofgem** and **Scottish Transmission Owners (TO)** across our full suite of proposed mechanisms through regular work group discussions, as part of the price control process, to ensure consistency across our submissions where relevant.

Finally, though the second half of 2019 we have undertaken detailed **bilateral engagement with Ofgem** to present our proposals, our underlying assumptions and analysis. Working versions of the Excel workbooks for volume driver UMs were shared, accompanied by detailed explanatory slide packs. A session detailing our approach to designing volume driver UMs has also been held with a sub-set of our **Independent Stakeholder Group**, to address their challenges on this aspect of our business plan.

3.0 The uncertainty landscape in the T2 period

Chapter key messages	
	▪ Uncertainty in the energy sector is intensifying ▪ £729m- £1994m of TotEx uncertainty linked to supply and demand ▪ More than £700m of TotEx uncertainty linked to whole systems ▪ More than £750m of TotEx uncertainty linked to externally driven factors

The need for UMs that deal with cost and volume uncertainty in an ex-ante price control continues into the T2 period. Our T1 period experience and the views of stakeholders emphasises that the requirements from the network are changing rapidly and our UM designs need to keep pace. Despite the shorter price control period, uncertainty will intensify in the T2 period and it's therefore vital we bring forward proposals for UMs which are robust. It's also prudent we bring forward new UMs in areas not covered in the T1 period, but where uncertainty now exists.

3.1 Uncertainty in the energy sector is intensifying

Uncertainty in the T2 period ranges across three areas:

1. **Supply and demand uncertainty** – changes to customers connecting to the system, and resulting wider flows across networks;
2. **Whole systems uncertainty** – uncertainty generated by maintaining the option to identify and deploy whole system alternatives to meet system requirements at lower cost to consumers
3. **Externally driven uncertainty** – uncertainty related to changes in legislation, policy or technological advances currently unknown and which may emerge during the T2 period

Wider factors such as performance of the economy, political developments and technology innovation influence the uncertainty faced across all three areas. Table 3 summarises a non-exhaustive list of the underlying sources of uncertainty, which could change our investment requirements.

Table 3 – Underlying sources of uncertainty in the T2 period

Source of uncertainty in the T2 period
Net-zero policy directives (*including decarbonisation of transport and heat*)
Outcome of whole system assessments
Technology developments (*including digitisation*)
Brexit & other political uncertainty
Industry policy & codes developments (*including competition*)
Pace of decentralisation
Growth in the wider economy

In line with Ofgem's guidance we have developed our baseline business plan to be consistent with the low-end of the industry's Common Energy Scenario. We believe that this provides a consistent, but conservative view of potential customer activities across the T2 period.

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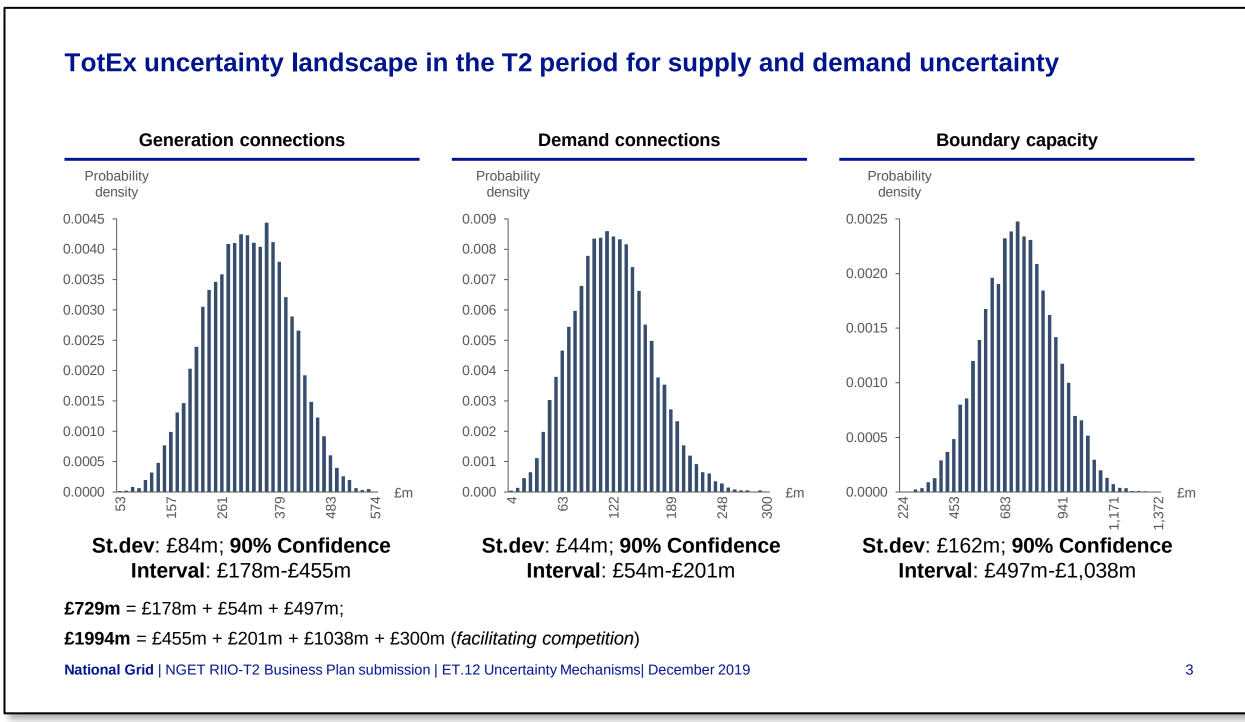
Our UMs are designed to allocate risk to whoever is best placed to manage it. For example, consumers can best manage uncertainty about the route to net zero emissions because the route will reflect changes in their behaviour. We are best placed to manage uncertainty over the costs of achieving the outputs consumers want.

3.1.1 £729m- £1994m cost uncertainty linked to supply and demand uncertainty

Our analysis indicates that changes to customer requirements of our transmission network in the T2 period drives a TotEx uncertainty range between £729m - £1994m, covering generation connections, demand connections and boundary capability. This is broken down in figure 3, using the outputs of our Monte Carlo analysis (*repeated random sampling of potential investments to meet system requirements to model the probability of different outcomes*).

Additionally, included within the £729m - £1994m range is spend for facilitating competition, i.e. achieving consents on large contestable projects (>£100m). This is not shown graphically in figure 3 given the limited number of projects which fall into this cost bracket but, we foresee this cost uncertainty range being >£300m, covering projects such as Eastern Link 3 and Torness-Lackenby reinforcement.

Figure 3 – TotEx uncertainty landscape in the T2 period for our three largest volume driver UMs



The range illustrated in figure 3 reflects a randomly selected (*repeated 10,000 times*) range of outcomes to deliver the baseline level of capacity, based on an underlying set of possible project costs.

Our set of project costs is extensive, associated with different types of works that we may deliver in the T2 period. These costs have been calculated through analysing system needs as signalled in publicly available data sources such as the ESO's Future Energy Scenarios (**FES**), the NOA, Electricity Ten Year Statement (**ETYS**) documents, the Transmission Entry Capacity (**TEC**) Register for generation connections, as well as our customer data for demand connections. We have also used historic T1 period project data to allow us to create a wide sample size.

Each data point has been rigorously checked to ensure consistency with data referenced in other parts of our submission, and with data held locally in National Grid. Where applicable we have cross-checked data with that held by the ESO, for example on boundary capabilities, for consistency.

To allow analysis to proceed it has been necessary to make some assumptions, for example on common data applicable to all mechanisms, and in some cases to omit data points from the underlying data set.

- On **boundary capability,** where we have chosen to not include projects >£100m in cost. This reflects guidance provided by Ofgem that projects >£100m are to potentially be considered as Large Onshore Transmission Investments (**LOTI**) and so subject to a specific assessment outside of our baseline ex-ante allowance;
- On **generation connections,** we have omitted T1 project costs data where the customer subsequently terminated their project (*for example Abernedd and Wylfa Newydd*);
- On **demand connections**, we have omitted a few high cost T1 project data points. For example, where underground tunnelling has been required, such as Islington and New Cross. The cost of underground tunnelling is a significant spend in projects and typically means they exceeds >£100m

As a result, the data used to create the ranges shown in figure 3 reflects the changing landscape we expect to deliver against for the T2 period, including 40% of generation customers contracted to connect in being less than 100MW, especially more batteries and gas reciprocating engines - incentivised by the capacity market. The data also reflects efficiencies from the T1 period such as higher volumes of power flow controllers (*a.k.a Smart wires*) in our boundary capability data set.

In building our proposal for other volume driver UMs, such as facilitating competition (pre-consents) and low voltage substation re-builds the available data set has been narrower. This is a reflection that these investments are less common in the T1 period, compared to areas such as generation and demand connections. Equally, the cost uncertainty range for the T2 period is anticipated to be narrower. We have therefore applied different analytical techniques to model proposed UCAs.

The accompanying Appendix A.2 (*Data & assumptions*) and Excel workbooks include a full list of the data points used in our analysis, the underlying data sources and relevant assumptions pertinent to the analysis including data points omitted, and a discussion on treatment of outliers.

To give more depth to our range in figure 3 we have calculated the standard deviation and the 90% confidence interval[1], see table 4. These represent the level of risks consumers and network companies would be exposed to in the absence of any UM. They also show how relatively conservative the baseline proposal is, which has been built from the projects we anticipate delivering against requirements for the low end of the Common Energy Scenario.

Table 4 – Risk metrics associated with supply and demand UMs in the T2 period

Uncertainty Mechanism	Standard deviation (£m)	90% cost uncertainty range (£m)	*Baseline proposal (£m)*
Generation connections	84	178 – 455	*216*
Demand connections	44	54 – 201	*89*
Boundary capability	162	497 – 1,038	*507*
Facilitating competition (pre-consents)		0 – 300	*182*

3.1.2 More than £700m of TotEx uncertainty linked to whole systems opportunities in T2 period

Uncertainty generated by excluding anticipated TotEx requirement from our baseline plans to allow whole system alternatives to be identified and delivered within the T2 period could exceed £700m.

Taking a whole systems approach to investing is something we have been doing extensively in the T1 period. Annex A7-8.03 'Whole Systems' provides deeper coverage of how we have developed a whole system plan and what more we recommend being done through setting this price control.

In several investment areas, such as managing increasing **fault levels from embedded generation**, **system operability**, **protection and control**, and **managing harmonic distortions** we firmly believe undertaking a whole system review of options prior to investing is in consumers' interests. The full extent of the investment required, and the party best placed to deliver will only emerge once a whole system review of options have been undertaken. When transmission investments are identified as being in consumers' interest, a UM that adjusts allowances and therefore gives us the flexibility to deliver these investments will be necessary.

Fault levels exceeding the rating of substation assets presents a physical safety risk as well as a risk to security of supply. It's a growing issue, as the trend for more embedded generation on the system intensifies. Currently we work with DNOs and the ESO to determine if any non-build options can resolve anticipated fault level issues. This has included changes to running arrangements in either the transmission or distribution network. However, the scope to undertake non-build solutions is finite and replacing equipment that has reached its maximum capability with higher rated equipment may become increasingly necessary.

We are not proposing baseline spend for the T2 period for managing fault levels. Instead we feel continual whole system review within the T2 period and a UM are prudent tools to

[1] 90% of samples have a total cost between these two numbers

manage the issue. If we did need to upgrade assets we estimate a total uncertainty range of up to £105m through the T2 period, as illustrated in figure 4. This covers 12 sites where we believe an issue could materialise soon under the Common Energy Scenario, based on our analysis and engagement with DNOs. Excluding these investments from our baseline and having a UM allows us to continue to work with relevant DNOs and the ESO as more information becomes available to determine what is needed and who is best to deliver, maximising to the overall benefit of consumers.

Figure 4 – TotEx uncertainty range to manage higher volumes of embedded generation with Tx assets

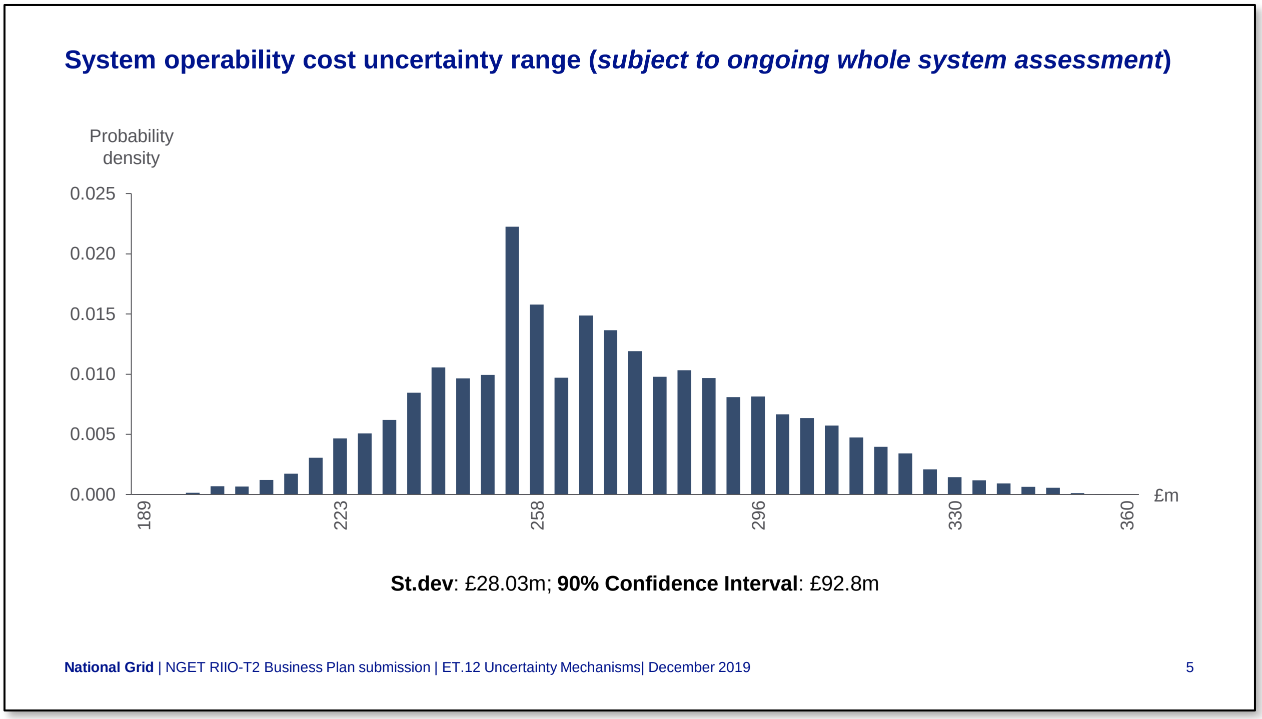
[redacted]

Voltage (*System Operability*) on the system is increasing due to reduced reactive power demand (*e.g. less heavy industry and changing domestic technology*), and periods of lower transmission flows because of increasing embedded generation. Today, the system voltage is managed through both network assets, like reactors and circuit switching (*increasing load to decrease volts*) or through the market, such as paying generators for real power to control reactive power etc.

The ESO has indicated in its Operability Strategy document that it needs access to new sources of reactive power. **In our baseline proposals we have justified £30.7m to deliver [redacted] shunt reactors** on the transmission network in areas where we know through working with the ESO and DNOs in a whole system study through the Electricity Networks Association it is prudent to have a transmission solution to manage static voltage issues. **For investment beyond the baseline we believe a whole system assessment is prudent** which considerers the range of alternative solutions and identifies those in consumer's best interests.

Through the Security and Quality of Supply Standards (**SQSS**) the obligation to manage network voltages sits with the TO in planning timescales. It's prudent therefore to quantify the cost uncertainty range if TO assets were the only option to manage static voltage issues. Figure 5 shows the outcome of our analysis. Taking account of our proposed baseline, our total cost uncertainty range is ~£289.4m[2]. To put figure 5 in more context, in the Common Energy Scenario 35 reactors would be required in the absence of other solutions. This rises to 45 in a Community Renewables scenario, which has significant levels of embedded generation and changes in consumer behaviour.

Figure 5 – System operability (voltage) cost uncertainty range (*subject to ongoing whole systems assessment*)



In direct response to stakeholder challenge through the enhanced engagement process **we are proposing a second System operability UM to provide allowances where an ESO whole system assessment of requirements (*other than voltage*) indicate a transmission network solution is best for consumers.** Examples of transmission assets that we may be required to deliver include synchronous condensers to manage system stability, and inter-trips where these represent a more economical alternative to transmission capacity. We are proposing an in-period determination in response to feedback from the ESO, the Independent Stakeholder Group and the RIIO-2 challenge group.

[2] £320.1m - £30.7m; where £320.1m is the 95% percentile and represents the upper bound of the 90% confidence interval shown in figure 5.

Operating a zero-carbon system with the high volumes of renewable and decentralised generation this entails means ensuring **our protection and control systems** are robust to meet the challenge of low system inertia and short circuit levels.

The specific requirements for investing in protection and control systems will continue to emerge as we work with the stakeholders and undertake the detailed modelling set out in our baseline plan. Our proposed in-period determination is built through extensive engagement with them to understand the evolving operational context and the requirements from our network to allow the ESO to be able to operate a carbon free network by 2025. We worked with an external consultancy, Quanta Technology, to study the available options and likely costs of ensuring our protection and control systems will continue to operate as required with increasing volumes of renewable generation. Our proposal for an in-period determination following the completion of detailed system modelling and coordination avoids consumers paying for work until the exact requirements emerge.

In summary we are proposing a baseline allowance of £31.1m in the T2 period to deliver a coordination study and changes to protection settings. Subject to enough progress of the study, further investment to replace or upgrade equipment may also be necessary at an estimated cost of ~£90.2m, which we propose be subject to an in-period determination.

A further implication of operating a system with high volumes of renewable and decentralised generation is ensuring power quality on the system remains within the limits so that consumers receive a stable and dependable voltage supply. **Frequency harmonics** are introduced by new connections through power electronics that are associated with renewable generation and interconnectors.

As the volume of these types of connections increases, so does the requirement for harmonic filters to mitigate their impact. In preparing our business plan, we looked to understand the opportunity of optimising harmonic filter placement on the system, given many of the new connections join the main system in similar geographic locations.

By having the network owner optimise and deliver the harmonic filters, rather than the customers connecting to the network, the total volume of filters required and therefore overall cost can be reduced. Our stakeholder engagement in this area has been positive. Working with external experts Atkins, we estimate for the period up to 2030, a customer led approach would require approximately [redacted] filters to be installed, with a whole life cost of ~£146m. If we delivered the filters, [redacted] would be required with a whole life cost of ~£119m. **We are not proposing any baseline funding associated with delivering harmonic filters. Instead once it's been agreed that we are best placed to deliver these, we will request the funding through an in-period determination. For the T2 period only, we estimate expenditure to be between £60m-£100m.**

3.1.3 More than £750m of TotEx uncertainty linked to externally driven factors

Shifts in the external political and societal environment in which network companies operate are likely to continue. Stakeholder engagement and an appraisal of the wider market, political and technology context have been pivotal to bringing forward sensible proposals for in-period determination UMs covering the T2 period. In section 2.3 we outlined that stakeholders have told us UMs need to continue for the T2 period and should be extended to cover new areas of uncertainty. This engagement has also aided us in shaping our specific proposals.

Several proposed industry policy changes, such as the revised black start standards have already been flagged by government and will require updates to the business plan to reflect mandated changes. On **black start,** the full extent of investment beyond the minimum of £[redacted]m included in our baseline plans for onsite low voltage restoration supplies is currently unknown and will not be known until the implications of the new standard are appraised. This is not likely to occur until closer to the start of the T2 period. Investing in additional **flood defences** is also subject to government direction. Whilst the probability of requiring additional spend is low, we feel it prudent to be able to adjust our plan should our requirements to invest be updated.

Ofgem have also directed network companies through the SSMD to bring forward proposals on two cross-sector in period determinations related to physical and cyber security. There is no current expectation that further spend will be required in the T2 period on **Physical Security** beyond the baseline plan, although the flexibility to bring forward an in-period determination is prudent as the national threat level from terrorist incidents related to our assets is subject to rapid change.

Changes to threat level are also relevant to **cyber security, both Operational Technology (OT)** and **Information Technology (IT)**. Here we estimate a cost uncertainty of ~£[redacted]m (~£[redacted]m OT and ~£[redacted]m IT) which also includes changes to investments as new technologies become available that it may be in sensible to invest in.

Sulphur hexafluoride (**SF_6**) is a highly potent greenhouse gas used to insulate equipment on the network where space is at a premium or environmental conidiations warrant its usage. Our suggestion to introduce an in-period determination for a **SF_6 replacement programme** went through acceptability testing. Further, 70% of technical experts on our SF_6 specific webinars said that the correct approach would be to undertake a targeted SF_6 Gas Insulated Line (**GIL**) replacement programme to remove the SF_6 footprint from the network all together, rather than just focusing on leak repair.

Our stakeholder engagement has indicated that the focus we had in the T1 period on the impact our assets have on local communities will continue in the T2 period. We feel the **VIP** scheme has worked well and, when asked there was strong support from consumers surveyed to take the programme forward for the T2 period; specifically, 66% of consumers surveyed found it acceptable for the costs of VIP to be recovered via household bills. Our stakeholder group also queried whether the visual amenity investment could be extended to disadvantaged urban areas, through an **Urban Impact Provision** (**UIP**). The proposal was tested with consumers groups in selected communities, such as Newport and Guildford, and received significant support with an indicative funding level of up to £50m per year. We therefore feel its prudent to have both VIP and UIP in-period determinations in the T2 period, where network companies can draw from shared allowances to fund specific projects approved by a stakeholder panel.

The UK's commitment to achieve net-zero greenhouse gas emissions by 2050 was passed into law in June 2019. Our business plan covers a crucial period when we all expect rapid change in the energy system to dramatically reduce carbon emissions to achieve the UK's net-zero by 2050 target. Our plan highlights specific opportunities within the regulatory framework, to enable and accelerate the UK's progress to net zero whilst minimising the cost to consumers. We are putting forward collaborative, innovative, and whole-system solutions to support policymakers. We are reinforcing this with commitments to reduce our own emissions to deliver the UK's net-zero target and ensure no one is left behind in the energy transition.

There could be new net-zero requirements on energy network companies in the T2 period, because the UK's target was only put into law in June 2019, and there remains a lot of uncertainty in government and the energy sector about the best pathway to achieve it. As the UK government starts to define its policy for low-carbon power, heating and transport (*and other sectors*) in more detail there might be new requirements for energy network companies. **As such we are proposing an in-period determination to allow for any net zero investment outside of that already agreed and other UMs to happen in a timely manner.**

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4.0 Our approach to designing rigorous and comprehensive proposals

Chapter key messages	
	▪ Advanced analytical techniques are required for a complex data set ▪ We have used a rigorous analytical framework to develop designs ▪ Complexity and accuracy must be traded-off in all designs examined ▪ We have used Monte Carlo analysis to differentiate between designs

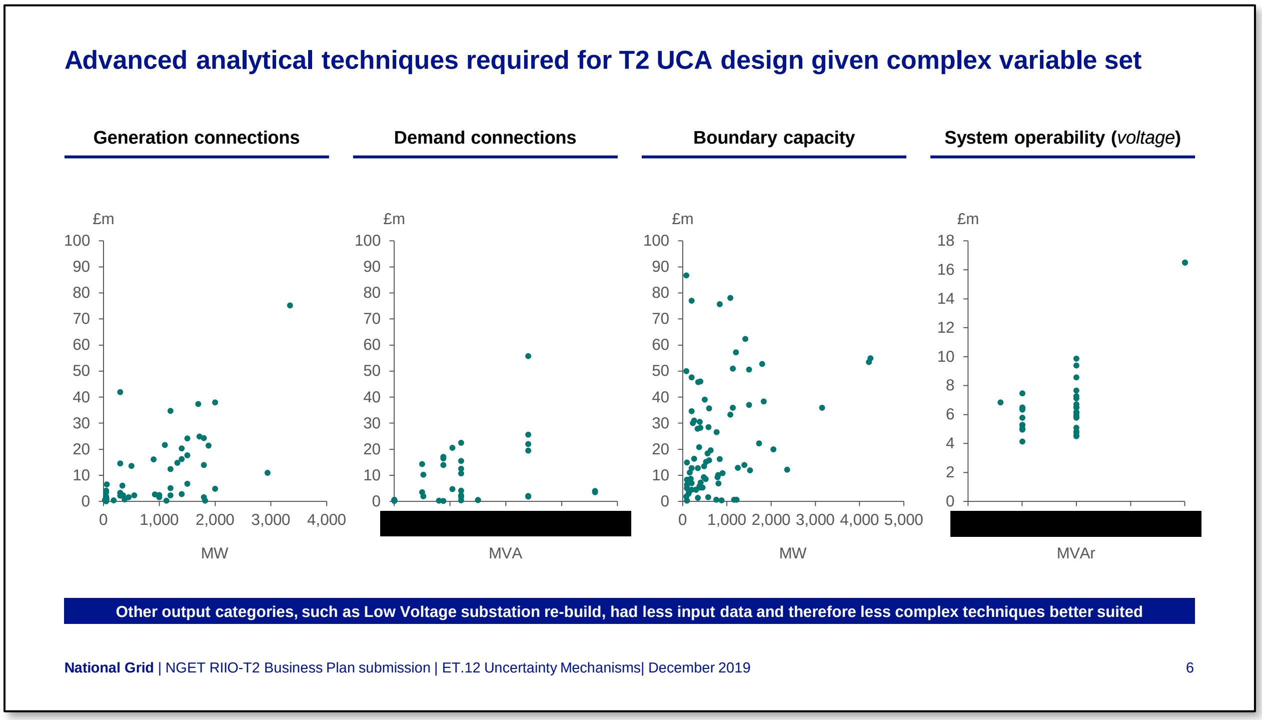
4.1 Volume driver UM design developed through robust analytical approach

Cost uncertainty in the three largest volume drivers from T1 period highlighted in figure 3 shown earlier and system operability (*voltage)*, figure 5, is extensive. Designing an accurate UCA in each area covering all possible costs is challenging. Figure 6 confirms this point by plotting the relationship between the main explanatory variable (*see x-axis labels in figure 6*) and cost (*£m*) for all the projects in the underlying data set sampled to create the uncertainty cost ranges. It reflects a highly complex data set with no obvious relationships between cost and output. The cost drivers are many and varied and at times they can differ from project-to-project.

For each volume driver UM, we have developed several design options, based upon different cost drivers. Some are output based, providing a cost per unit of capacity delivered, e.g. MW, whilst some are based upon a defined asset e.g. SGT.

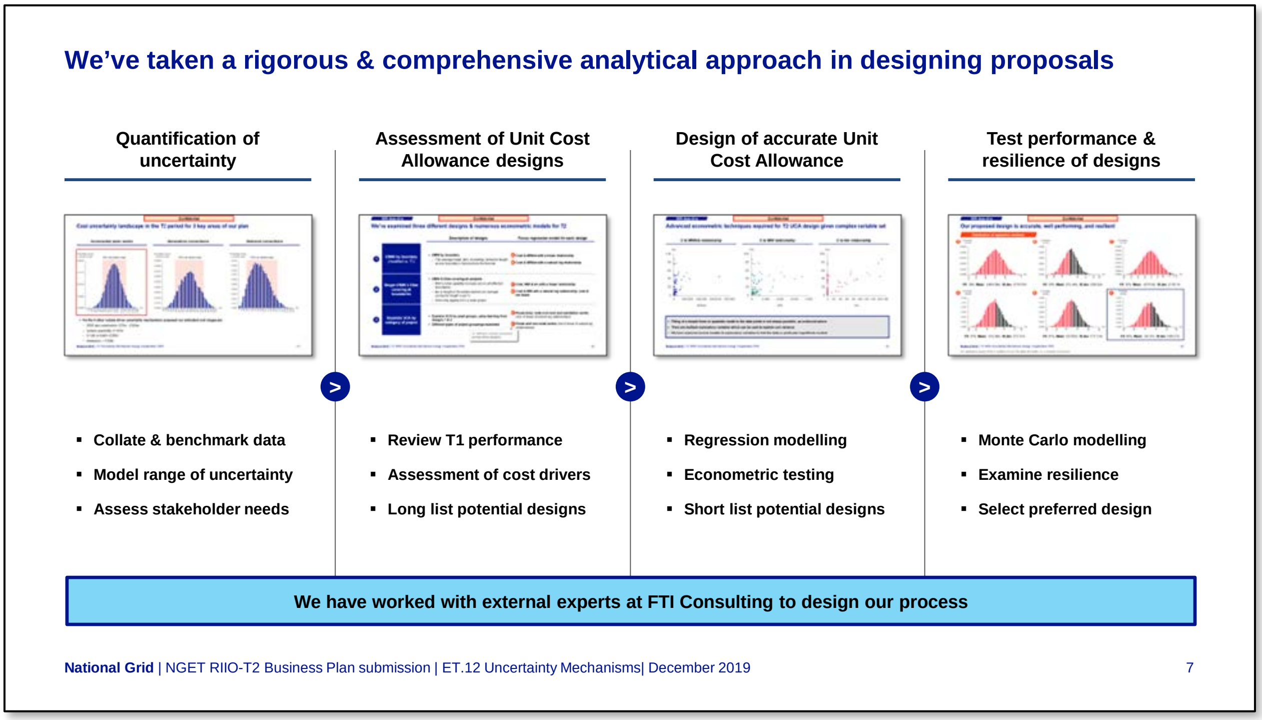
Specific asset based UCAs narrow the scope for innovation in meeting customer requirements. Nevertheless, occasionally they are a necessity, when the range of possible options for network investment is known to be narrow and there is limited correlation between the output and cost. Low Voltage substation re-builds is an example, where we propose an asset based UCA. The rationale for using assets based UCAs is explained in appendix A.3 (*Specific proposal detail*).

Figure 6 – Cost & output relationship for our four largest volume driver UMs in the T2 period



Developing UCAs to reflect the data range shown in figures 3, 5 and 6 require a flexible approach with a careful trade-off between complexity and accuracy. A robust analytical framework was developed, as shown in figure 7, allowing us to find accurate and well-fitting relationships in our underling data.

Figure 7 – Our analytical framework



For the generation, demand and boundary capability volume drivers used in the T1 period we reviewed several alternative designs for the UCA, as well as continuing the T1 period approach, to explain the cost to output relationship, as shown in figure 6. These designs reflect lessons learned, stakeholder feedback, and the T2 period uncertainty landscape.

In the T1 period, most of the designs across all volume driver UMs where relativity simple. This simplicity is part of the reason why costs did not better track allowances. The alternative T2 period designs investigated capture a range of factors, such as location and asset types in addition to outputs. Our designs have been built bottom-up using a detailed analysis of cost triggers. As an example, figure 8 highlights the different designs examined for the boundary capability UM, showing one example of the thought process undertaken across all volume driver UMs.

Figure 8 – Example of UM design considerations (Boundary capacity)

Three alternative boundary capability UM designs for consideration in the T2 period

	Design	Description	Advantage/ Disadvantage
	(Existing) £/MW by boundary	▪ *£/MW by boundary* – *High/low value range also given to adjust for allowed baseline changes*	✗ *Built boundary-by-boundary from narrow set of works* ✗ *Used limited scenario range to calculate* ✗ *No asset type distinction*
1	**£/MW by boundary *(modified)***	▪ **£/MW by boundary** – The average length (km) of existing conductor length across boundary is factored into the formula	✓ **Accounts for route km cost variance** ✓ **Maintains regional cost variance** ✗ **No asset type distinction**
2	**Single £/MW & £/km covering all boundaries**	▪ **£/MW & £/km covering all projects** – MW is total capability increase across all affected boundaries – km is length of the reinforcement (*not average conductor length in opt 1*) – £/km only applies if it's a route project	✓ **Accounts for route km cost variance** ✓ **Gives some asset type distinction** ✗ **No regional cost variance**
3	**Separate UCA by category of project**	▪ **Examine UCA by asset groups, using learning from designs 1 & 2** ▪ **Different types of project grouping examined**	✓ **Accounts for route km cost variance** ✓ **Maintains regional cost variance** ✓ **Gives broad asset type distinction** ✗ **Introduces some complexity**

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For **boundary capability**, we examined six different designs in detail (*two sub-sets of each design in figure 8*), after an initial consideration of over 27 at a conceptual level. The designs test the influence on costs of factors like geographic location by including boundary lengths; and whether creating separate UCA values for route (*i.e. projects with an associated length like reconducting*) and non-route projects helped to better explain the cost to output relationship.

Similar detailed consideration of cost drivers was examined for generation and demand connection UM designs. For example, with **generation connections** we looked at seven different designs (*including continuing the T1 period model*) including whether a clearer relationship exists when projects were grouped as either connecting at a new or existing substation; and if substation design had a bearing on the relationship by splitting projects into those which are Air Insulated Substations (**AIS**) *vs.* Gas Insulated Substations (**GIS**). For **demand connections** seven designs (*including continuing the T1 period model*) were examined including whether a substation being defined as an infrastructure *vs.* connections site had a bearing on the cost to output relationship.

Appendix A.3 (*Specific proposal detail*) of this annex has a full list of all the alternate designs considered by UM and our associated Excel workbooks provide a deeper commentary on the designs cost drivers, for the generation, demand, boundary capability and system operability (*voltage*) UMs.

Whilst more detailed designs can sometimes be more complex, they are often more accurate (*cost reflective*). To measure this trade-off, we used analytical techniques to model each design and assess the additional benefits.

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The analytical framework makes uses of both regression analysis and distribution cost fitting. In regression analysis our aim is to predict a dependent variable (*in our case cost (£m)*) as accurately and precisely as possible using explanatory variables correlated with it (*in our case primarily MW, MVAr and/or km*). It isolates the average effect of each explanator on the cost as a 'regression coefficient', which is the UCA value in the given design.

Distribution cost fitting is more useful when we analyse the effect of a cost driver separately for different categories in our dataset, each of which has a small number of observations. It involves calculating the mean of unit costs for each data point (*e.g. £/MW or £/SGT by project*). The technique is particularly useful when the unit cost distribution can be segmented around specific cost drivers, increasing the accuracy of the mean. Such cases arise in the generation and demand UM analysis, when we look at how unit costs are distributed at a new GIS substation as opposed to those at existing AIS substations. A full explanation of all our techniques can be found in appendix A.1 (*Our analytical techniques*).

To differentiate between designs and their coefficients, we extensively tested for accuracy and resilience across the uncertainty range. We used Monte Carlo modelling, to create 10,000 different ways to deliver the baseline capability by randomly sampling the range of projects and measuring the difference between allowance generated by the design's UCA and the cost of the project sampled.

Two key metrics emerge from this process which we use to differentiate between designs in the UMs for generation, demand, boundary capability and system operability (*voltage*):

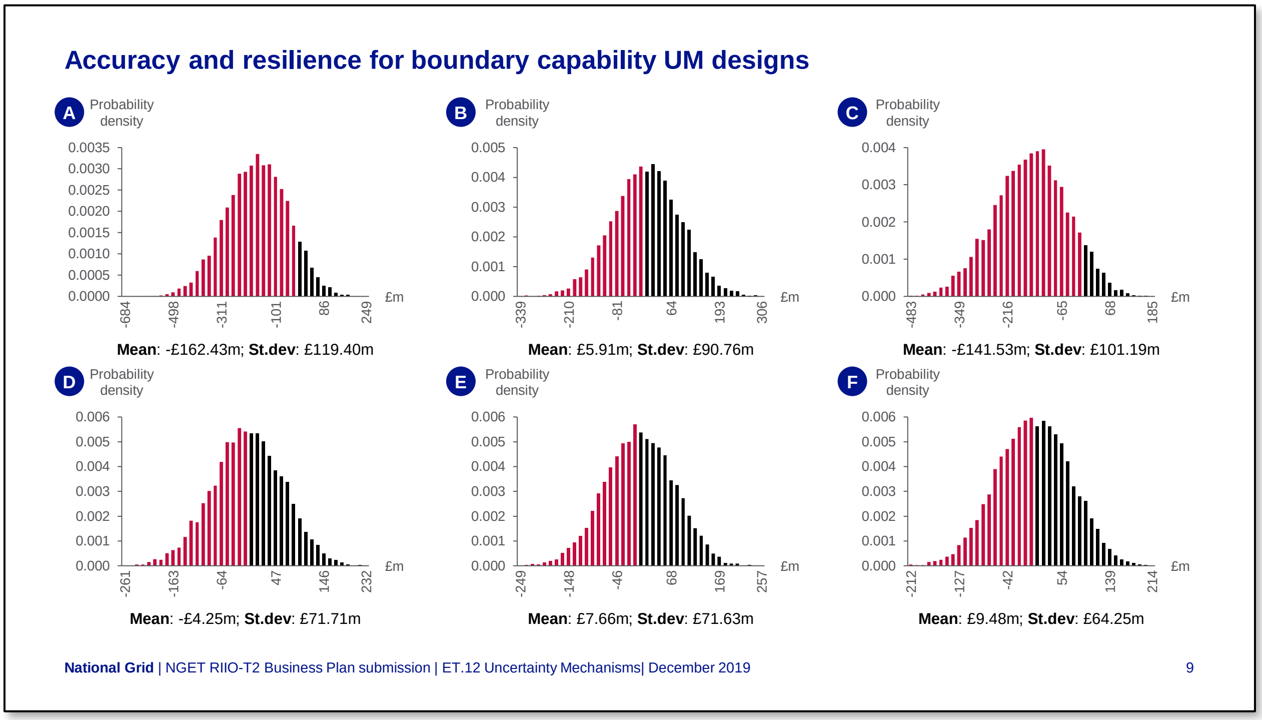
1. **Mean** – is a measure of accuracy. The average difference between allowance and cost when measured over 10,000 random samples. The closer this value is to zero the better, as zero represents a point where there is an equal likelihood of costs exceeding or being less than allowances for a given design;

2. **Standard deviation** – is a measure of the resilience. The amount of variation from the mean, when measured over 10,000 random samples. The smaller this value the better, as a narrower standard deviation indicates allowance would track costs more closely, hence reducing the risk to consumers of extreme fluctuations

Figures 9 illustrates how measuring mean and standard deviation of 'allowance – cost' helped to arrive at our preferred model for the boundary capability UM. In this case model F, which is our proposed design, has a mean close to zero and the lowest standard deviation. We have picked this over model E because it is within an acceptable tolerance range but has lower variation at the extremes.

Appendix A.1 (*Our analytical techniques*) provides a more detailed explanation of analytical techniques employed, sign-posting where they have been used and our rationale for using them. The accompanying Excel workbooks show our analysis using the techniques step-by-step.

Figure 9 – Accuracy and resilience assessment of boundary capability designs



5.0 Our proposals on a page

We propose a total of 21 UMs as part of our package of proposals, alongside our baseline plan, to deliver for stakeholders in the T2 period (*excluding financial indexation and cost pass-through*). Six volume drivers and 15 in-period determinations to mange supply and demand uncertainty, whole system uncertainty and, externally driven uncertainty.

In sections 2.0, 3.0 and 4.0 of this annex we outlined how we progressed from the T1 period, learned key lessons, quantified the uncertainty for the T2 period, used robust analytical toolkit and took on-board stakeholder views to create a robust set of proposals. This section of the annex summarises our proposals on a single page, see table 5. In the appendices to this annex further detail is provided on each mechanism, structured around Ofgem's Business Plan Guidance on UMs, and the accompanying Excel workbooks provide the raw data used and give a step-by-step guide to how we have developed our proposals for volume driver UMs covering generation connections, demand connections, boundary capability and system operability (voltage).

Table 5 - T2 period UM proposals on a page

Theme	Proposed UM	T2 UM type	T2 proposal summary	T2 cost uncertainty	*T1 mechanism summary*	Submission chapter
Supply & demand uncertainty	**UM7-1:** Boundary capability	Volume driver	▪ Separate UCAs for route and non-route projects ▪ Include pre-construction and extend TPWW to cover ▪ Apply cable expansion factors	£497m – £1,038m	▪ *£/MW allowance specific to each boundary* ▪ *£/km for cable undergrounding based on 2012 IET report*	**Chapter 7:** Enable the transition
	UM7-2: Facilitating competition (pre-consents)		▪ £/km UCA (*separate for onshore and offshore projects*) for delivering consents on contestable projects ▪ TPWW approach used if a project we are developing terminates	>£300m	▪ *Fixed ex-ante funding allowance with ability to substitute between projects*	
	UM8-1: Generation connections		▪ Separate UCA for AIS *vs.* GIS sites, and then further split by new and existing sites and whether the connection is above or below 100MW	£178m – £455m	▪ *£/kW allowance for a new connection* ▪ *£/km OHL and cable allowance based on 2012 IET report*	**Chapter 8:** Easy to connect & use
	UM8-2: Demand connections		▪ Separate UCA for connection and infrastructure sites ▪ Connection site UCA further split by capacity & type of site ▪ Infrastructure site UCA split SGT *vs.* no SGT requirement	£54m - £201m	▪ *£/SGT allowance for a new connection* ▪ *£/km OHL and cable allowance based on 2012 IET report*	
Whole systems uncertainty	**UM7-3:** System operability (voltage)		▪ UCA for static and dynamic compensation equipment with separate UCA values for static devises depending on capability required	£30m-£320m	▪ *Assessed through the mid-period review*	**Chapter 7:** Enable the transition
	UM8-3: Low voltage substation rebuild (embedded generation)		▪ £m/substation for each new substation required ▪ Allowance of items selected from menu when individual assets require replacing (*e.g. circuit breakers*)	~£105m	▪ *Assessed through the mid-period review*	**Chapter 8:** Easy to connect & use
	UM7-4: Protection and control	In-period determination	▪ One determination following completion of studies on additional investment requirements for protection and control equipment	~£90.2m	▪ *No mechanism in T1 period*	**Chapter 7:** Enable the transition
	UM 7-5: Whole System Co-ordinated adjustment mechanism		▪ Continue to work with Ofgem and industry on detail of CAM operation through the draft and final determination stages	Currently unknown	▪ *No mechanism in T1 period*	
	UM7-6: Harmonic filtering		▪ In-period determinations to allow NGET aggregate and deliver harmonic filtering requirements following agreement with our customers	£60m – £100m	▪ *No mechanism in T1 period*	
	UM7-7: System operability (other ESO requirements)		▪ In-period determinations following ESO trigger of TO solution to manage System operability issues for investments >£20m ▪ Automatic allowance adjustment and logging up for investments <£20m	£50m-£100m	▪ *No mechanism in T1 period*	
Externally driven uncertainty	**UM10-1:** Extreme weather		▪ One determination triggered by ETR138 or as directed by BEIS to protect sites against flooding	Currently unknown	▪ *No mechanism in T1 period*	**Chapter 10:** Protect from external threats
	UM10-2: Physical security		▪ Two determinations, one mid-way and one at end of T2 period ▪ Account for changes in Physical Security Upgrade Programme	Currently unknown	▪ *Two determinations, one 2015 and 2018* ▪ *Accounting for changes in PSUP*	
	UM-10-4: Cyber security operational technology (OT)		▪ Two determinations, one mid-way and one at end of T2 ▪ Directed by changing threat level and maturity of solutions	~£[redacted]m	▪ *No mechanism in T1 period*	
	UM10-3: Cyber security (IT)		▪ Two determinations, one mid-way and one at end of T2 ▪ Directed by changing threat level and maturity of solutions	~£[redacted]m	▪ *No mechanism in T1 period*	
	UM10-5: Black start		▪ One determination following confirmation of the new Black Standard by BEIS	Currently unknown	▪ *No mechanism in T1 period*	
	UM10-6: Ensuring a resilient electricity network		▪ One determination triggered by the emergence of new threats or changes to policy/ codes standards	Currently unknown	▪ *No mechanism in T1 period*	
	UM11-1: SF_6 replacement programme		▪ Allow for investment needed for our SF_6 reduction investment programme	>£150m	▪ *No mechanism in T1 period*	**Chapter 11:** Care for communities and the environment
	UM11-2: Visual Impact Provision		▪ In-period determinations to allow for the investment needed to take forward projects once we have fully developed our proposals	Currently unknown	▪ *Same as proposed for T2 period*	
	UM11-3: Urban Impact Provision		▪ In-period determinations for investment of up to £50m p.a. to improve our assets or public spaces, focused on the top 30% most deprived urban areas	~£250m	▪ *No mechanism in T1 period*	
	UM11-4: Net zero		▪ In-period determination for any investment needed in response to potential new requirements to achieve the UK's target of net-zero by 2050	Currently unknown	▪ *No mechanism in T1 period*	
	UM12-1: Innovation plan		▪ One determination to allow reshaping of innovation programme in 2022 to reflect the latest developments in decarbonisation and stakeholder requirements	Currently unknown	▪ *No mechanism in T1 period*	**Chapter 12:** Be innovative

APPENDIX A.1: Our analytical techniques

Section 4.0 of this annex emphasised the rigorous and robust analytical approach we developed to design volume driver UMs for the T2 period. Figure 7 outlined our analytical framework and its narrative commentary set out how we balanced the complexity *vs.* accuracy trade-off through examining cost drivers. We also introduced our use of regression analysis and distribution fitting on unit costs to calculate UCAs for each design and Monte Carlo analysis to differentiate between designs by calculating accuracy and resilience.

In this appendix, we provide a short explanation of the key analytical techniques employed, sign-posting where they have been used and our rationale for using them. A complete description of the techniques can be found in the accompanying Excel workbooks, which also show our analysis step-by-step.

A1.1 Determining a UCA for each design

A1.1.1 Regression Analysis

The aim of regression analysis to predict a dependent variable (*in our case: cost (£m)*) as accurately and precisely as possible using different explanatory variables correlated with it (*such as MW, substation type or technology, number of bays, or route length (km), etc.*). It isolates the average effect of each explanator on the cost as a 'regression coefficient', which is the UCA value in the given design.

A linear regression technique called Ordinary Least Squares (**OLS**) is our typical starting point for the analysis, which finds coefficients that minimise the sum of squares of residuals (*i.e. the difference between the cost used and the predicted costs values by the coefficients (UCA)*). It is a widely used regression technique, because in theory the OLS coefficients will be the best unbiased estimators, i.e. will lead to the minimum deviation of allowance from the estimated cost, if the data satisfies certain conditions:

- Dependent variable (*i.e. cost*) should be linearly related to the explanatory variables;
- Data should have a distribution that is a near normal distribution, so the confidence intervals can be built for the coefficients;
- Residuals should not be correlated with cost (*i.e. the residuals should have zero mean given the explanatory variables);*
- The residuals should not be correlated with each other, and they should be randomly distributed with a constant variance across different levels of explanatory variables

Before we progress a UCA from a regression model to Monte Carlo testing, we assess its econometric validity by comparing models based on the following regression results:

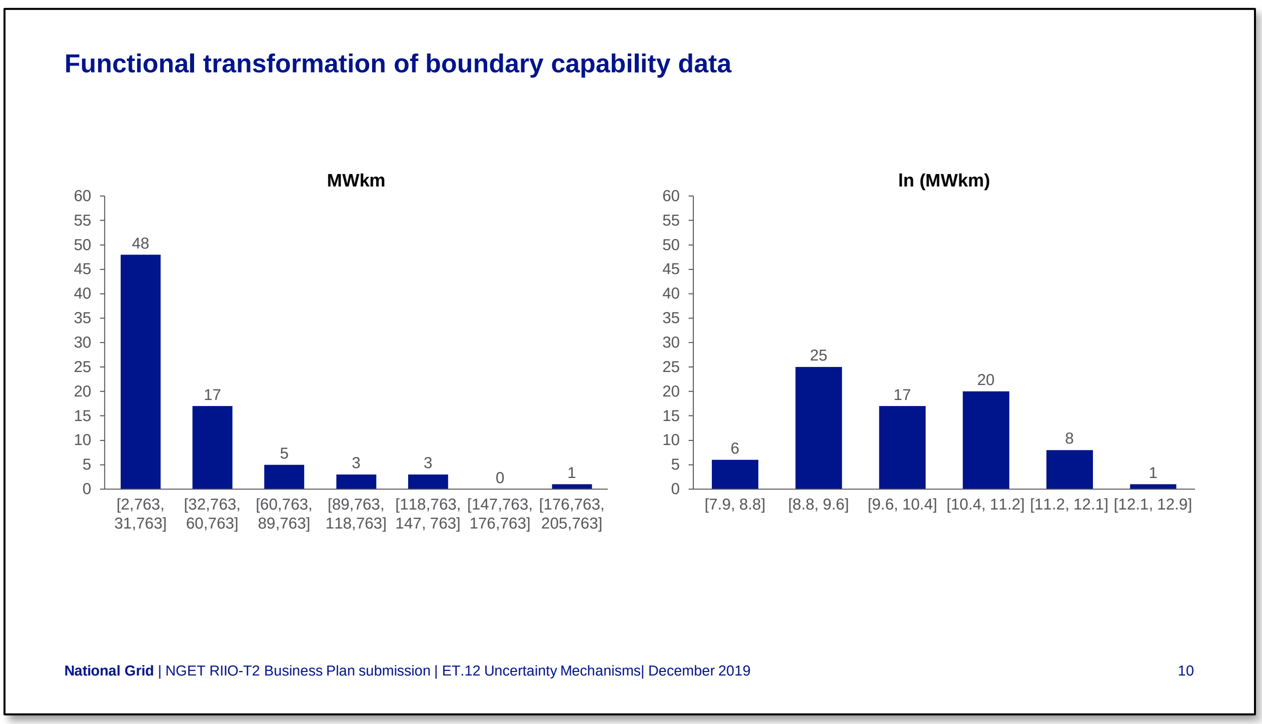
- After ensuring that it has a valid confidence interval, we check that the coefficient is statistically significant (*i.e. not showing any obvious false positives*);
- Explanatory power of the variables on cost *(R^2)* is reasonably high;
- Distribution of the residuals satisfy the OLS condition presented above (*random distribution without a trend or autocorrelation, and with constant variance across different values of the explanatory variable*)

If a model does not satisfy a condition to a satisfactory degree, we may use functional transformations of potential cost drivers, such as converting the data to the natural log domain. This often helps ensure both the linear relationship between cost and the explanator remains and it can achieve a closer to normal distribution of the explanator data. If a functional transformation is not sensible, we can use econometric techniques that relax the distributional assumptions in the OLS, such as 'bootstrapped OLS coefficients' or 'quintile regression analysis'. These are further demonstrated in the Excel workbooks.

One example where the OLS regression assumptions were not satisfied for one of our cost drivers was in the Boundary capability UM analysis. Figure 10, left hand chart, shows that output (MWkm) data across projects is significantly left-skewed (*i.e. not close to a normal distribution),* which means that we were not able to construct confidence intervals around our coefficients.

1. The first solution we explored was to use the natural logarithm of output (MWkm). This gives a much closer distribution to a normal as seen on the right hand chart in Figure 10.

Figure 10 – Example of the distribution of data & how transforming can help improve normality



2. The second solution would be to 'bootstrap' the OLS regression coefficients. This technique involves repeating the OLS regression thousands of times after the original analysis, using the random assignment of original residuals to create a minimally different dataset each time. The resulting distribution of thousands of coefficients can then be used to create a confidence interval, without relying on a normal distribution assumption. The 'bootstrapped coefficient' is the mean of the coefficients from thousands of bootstrap samples, and represents our UCA if this technique is used

A1.1.2 Distribution fitting on unit costs

An alternative to regression analysis is to look at the distribution of unit costs by several cost drivers across the schemes in our dataset. This analysis involves looking at the mean of the entire distribution of unit cost (*e.g. £/MW or £/SGT*), or the mean of part of it. This is particularly useful when the unit cost distribution can be segmented around specified cost drivers, increasing the accuracy of the UCA. We have used this technique in the generation, demand and system operability (voltage) UM analysis, when we examined how unit costs are distributed at GIS and AIS substations and at 400kV and 275kV substations. We calculate the unit cost implied by each data point, e.g. £/MW and use statistical software to test the fit of several curves (*exponential, lognormal, uniform, etc.*) through the data points to identify the curve with the best fit. Figure 11 shows how we have applied a uniform fit to new demand substations.

Figure 11 – Distribution fitting on unit costs for new demand substations

[redacted]

The mean of the distribution, or the mean part of it, is used as the UCA value. Typically, the mean of the fitted curve is a good approximation of the average unit cost. Therefore, we used 'average' unit cost as the UCA value of that specific model to reduce complexity and ensure results can be easily reproduced.

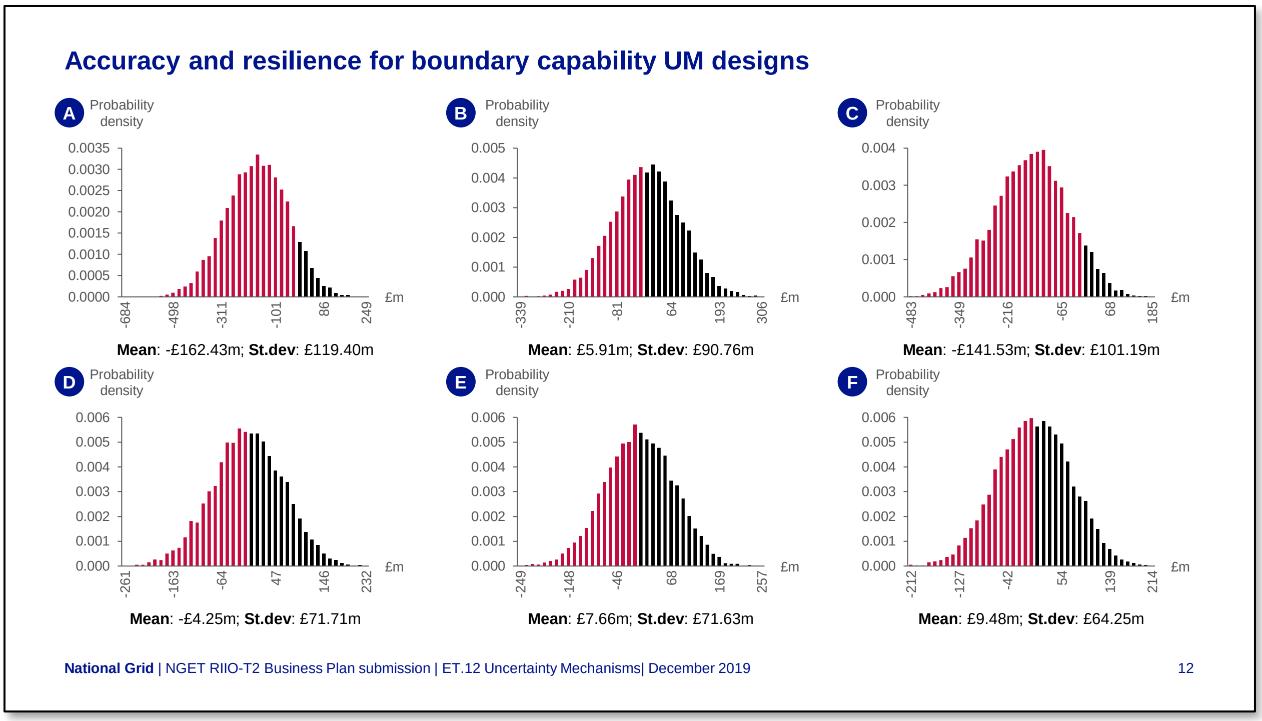
A1.2 Differentiating between designs to select the optimal (*Monte Carlo analysis*)

Monte Carlo simulations involve repeated random sampling to generate a distribution (*histogram*) of probable results. In our UM we do this on the 'allowance minus cost', which quantify the benefits of alternative models.

The Monte Carlo analysis involves randomly sampling, typically 10,000, different ways to reach the target T2 period capability from our available set of projects.

Looking at the distribution of total mismatch (allowance – cost) resulting from a specific UM model, we can focus on metrics such as mean (*a measure of accuracy*) and standard deviation (*a measure of resilience*). We select the model with the lowest standard deviation and a mean closest to zero. This means the design has a near equal probability of total costs being higher or lower than allowance and the risk to consumers of large fluctuations is minimised. Model F, in figure 12 in this example from the boundary capability analysis in demonstrates this.

Figure 12 – example outputs from a Monte Carlo simulation to differente between models



APPENDIX A.2: Data & assumptions

Section 3.1.1 of the annex outlined the data sources used and key assumptions made to allow the analysis to proceed. In this appendix we provide deeper coverage for each volume driver mechanism. We also provide commentary on overhead line and cable unit costs which are commonly used in the generation, demand and boundary capability analysis.

A2.1 Generation connections data

Table 6 – Generation connections data and assumptions

Data Source	Notes
Contracted projects	Future generation connection projects where a customer has applied for and accepted a connection offer. The scope and cost of works are specified in these contracted offers.
Assumptions	
▪ A snapshot of the contracted connections portfolio (*as per the TEC register*) was taken when analysis commenced. Projects that have since terminated have been excluded from our dataset ▪ Projects with connection dates in the T3 period have been included to increase the number of data points available. These projects are representative of potential T2 period connection types, when considering requirements to meet net-zero targets	

A2.2 Demand connections data

Table 7 – Demand connections data and assumptions

Data Source	Notes
Contracted projects	Future demand connection projects where a customer has applied for and accepted a connection offer. The scope and cost of works are specified in these contracted offers.
Historical projects	Demand connection projects that have been delivered or will be delivered in the T1 period.
Assumptions	
▪ Projects that represented cost outliers were excluded from our analysis – e.g. projects that involved the construction of a tunnel. These are unique features that have a significant impact on cost and are not anticipated to occur in the T2 period ▪ Also excluded are projects that required SGTs or new GSPs to be delivered for reasons other than DNO growth. For example, where the transmission network is re-configured and 'demand assets' must be delivered to maintain security of supply for a DNO. These projects can differ in scope from a 'standard' demand connection and hence are excluded. Taking down the DNO circuits on the Hinkley-Seabank route corridor and replacing with additional SGTs is an example of this	

A2.3 Boundary capability data

Table 8 – Boundary capability data and assumptions

Source of data	Note
Baseline capabilities	All projects in baseline feature in the underlying data set
NOA 2019	NGET projects submitted to NOA 2018/19
Historical projects	We included non-route projects from the original T1 baseline
NGET Internal	Additional power flow controllers not in NOA 2018/19 but in NOA 2019/20
ETYS	Used to provide length (km) of existing circuits across boundaries
NGET Internal	Length (km) of new route projects included in the NOA 2019 submission
Assumptions	
▪ We only include projects that are under <£100m in cost, as per guidance provided by Ofgem on the proposed LOTI framework	

A2.4 System Operability (*voltage*)

Table 9 – System operability (*voltage*) data and assumptions

Data Source	Notes
Historical projects	Reactive compensation projects that have been delivered or will be delivered in the T1 period.
High Voltage case study inputs	We provided a range of future reactor investment options into the ENA High Voltage Case Study project. These options were developed to a level suitable for use in our UM development.
Assumptions	
▪ Projects that represented cost outliers were excluded from our analysis. These projects constituted cases where specific site conditions resulted in very high installations costs, which are not expected to occur in the T2 period	

A2.5 Consents for facilitating competition (pre-consents) projects

Table 10 – Consents for facilitating competition projects data and assumptions

Source of data	Note
Baseline connections	All projects listed as baseline feature in the underlying data set
Historical projects	Projects, additional to baseline sourced consistent with RRP
Assumptions	
▪ Only projects >£100m cost have been used in the analysis ▪ Costs are those incurred up to the point of achieving consents (as opposed to pre-construction costs only)	

A2.6 Low Voltage substation rebuild

Table 11 – Low Voltage substation rebuild data and assumptions

Source of data	Note
NGET Internal	All projects sourced from internal cost analysis of works req.
Assumptions	
▪ Only selected substations where indicative analysis suggests upgrades to the TO assets would be required. These will be subject to a Whole System assessment during the T2 period	

A2.7 Overhead line and cable unit costs

Common to Boundary capability, generation and demand, we have used overhead line and cable unit costs as part of the analysis. The unit costs used are shown in table 12.

Table 12 – Overhead line and cable unit costs used in analysis

	Voltage	Single circuit (£/km)	Double circuit (£/km)
Cable new build	132kV	[redacted]	[redacted]
	275kV	[redacted]	[redacted]
	400kV	[redacted]	[redacted]
	Average cable	[redacted]	[redacted]
Overhead line new build	132kV	[redacted]	[redacted]
	275kV	[redacted]	[redacted]
	400kV	[redacted]	[redacted]
	Average OHL	[redacted]	[redacted]

In the boundary capability analysis, we have used the unit costs to derive expansion factors for cable circuits. In the T1 period an adjustment was made to our allowance for cable undergrounding costs using unit costs from a 2012 report by the Institute of Engineering and Technology (**IET**), authored on commission by Parsons Brinckerhoff (*now WSP Global Inc*.). Using these unit costs reflects that the cost of undergrounding is a significant additional cost for network companies. **For the T2 period we are proposing to simplify the approach by removing the undergrounding allowance and replacing this with a cable expansion factor.** The main benefit of expansion factors over the approach used in the T1 period is that they allow cable projects and the lengths of existing cable circuits to feature in the regression analysis, without having to make adjustments. This is useful when factoring in the length of existing circuits crossing a boundary.

Expansion factors applied to cable lengths allows all analysis to be done in 400kV/275kV overhead line equivalent terms. If we did not apply expansion factors, we would get different costs for the same route length and thus spurious regression results leading to a more complex approach to maintain cost reflectivity. The expansion factors are derived by dividing the cable unit cost in table 12 by the equivalent overhead line unit cost, the result is shown in table 13.

Table 13 – Expansion factors used for boundary capability analysis

Voltage	Single circuit (£/km)	Double circuit (£/km)
132kV	[redacted]	[redacted]
275kV	[redacted]	[redacted]
400kV	[redacted]	[redacted]

For generation and demand analysis the average unit costs for OHL in table 12 are used when beyond substation work is required.

The unit costs in table 12 are based upon on-going analysis and benchmarking of the latest market cost rates and are not project specific. For completeness we have benchmarked the NGET unit costs rates to those in the 2012 IET report, after adjusting for inflation. Table 14 demonstrates this comparison for single circuits.

Table 14 – Unit cost comparison to 2012 IET report

	Voltage	NGET single	IET single	£m Delta
Overhead line new build	132kV	[redacted]	1.33	[redacted]
	275kV	[redacted]	1.56	[redacted]
	400kV	[redacted]	1.79	[redacted]
Cable new build	275kV	[redacted]	10.99	[redacted]
	400kV	[redacted]	11.90	[redacted]

Table 14 highlights we are within an acceptable range of costs in comparison to the IET report considering that the IET report refers to cost sensitivity factors i.e. route length, ground conditions, etc, which are known to affect the unit cost. The NGET value does include the influence of these cost sensitivity factors.

In addition, the IET report uses a mean distance for their study. In our analysis we have employed a median (*10km overhead line & 9km cable*) to our underlying data sources, as the value has an equal chance of being over or under the eventual actual route length. We have therefore selected from the IET report a unit cost based upon route length where our median is within the IET distance range quoted for their mean calculation.

APPENDIX A.3: Specific proposal detail

UM7-1 Boundary capability	Chapter reference: 7	Volume driver
Proposal summary	**Route reinforcements** ▪ [redacted] **£m/ln(MWkm) +** [redacted] **£m/km** **Non-route reinforcements** ▪ [redacted] **£m/ln(MW)** **Additional details** ▪ Table of average cct length for each boundary in licence ▪ Apply cable expansion factors to all cable route lengths for calculating allowance ▪ Allow for additional boundaries to be added to the licence during the T2 period ▪ Include pre-construction in allowance and extend Transmission Provisions for Wider Works (TPWW) to cover ▪ UM is symmetrical in application (*i.e. allowance can be adjusted up or down by UCA*) with a £0m floor, to prevent risk of negative allowances ▪ TPWW is a automatic adjustment to the Annual Iteration Process with an a review at end of price control to protect consumers ▪ TPWW extended to cover additional spend above UCA in event of efficient delays ▪ The forecast of funding in future periods needs to be sufficiently flexible to accommodate plan changes ▪ Spend in T2 period for output in future periods should be funded in the T2 period	

Alternative options examined

- **T1 approach**: £/MW for each boundary
- **Model A**: UCA for each boundary (*£/MWkm*)
- **Model B**: UCA for each boundary in log domain (£ln(MWkm))
- **Model C**: Single system wide UCA: Capacity & length based (£/MW + £/km)
- **Model D**: Single system wide UCA: Capacity & length based in log domain (£/ln(MW) + £/km)
- **Model E**: Separate UCA per type of asset: route with km (*e.g. reconductoring*), route with no km (*e.g. hotwiring*), and non-route (*e.g. substation works*)
- **Model F** (*proposed*): Separate UCA per type of asset, split route with km, and non-route (*e.g. substation works and hot wiring*)

Results of analytical investigation

Table 15- Analytical performance of examined alternative boundary capability UM models

Model	Mean (£m)	Standard Deviation (£m)
F – Proposed model	**9.48**	**64.25**
T1 method	-124.06	123.00
A	162.43	119.40
B	5.91	90.76
C	-143.53	101.19
D	-4.25	71.75
E	7.66	71.63

Data & assumptions

Table 16 - Boundary capability data and assumptions

[redacted] data points in total assessed.

Source of data	Note
Baseline capabilities	All projects in baseline feature in the underlying data set
NOA 2019	NGET projects submitted to NOA 2018/19
Historical projects	We included non-route projects from the original T1 baseline
NGET Internal	Additional power flow controllers not in NOA 2018/19 but in NOA 2019/20
ETYS	Used to provide length (km) of existing circuits across boundaries
NGET Internal	Length (km) of new route projects included in the NOA 2019 submission
Assumptions	
▪ We only include projects that are under <£100m in cost, as per guidance provided by Ofgem on the proposed LOTI framework	

Triggers of use

- Project receives a proceed decision from the NOA

Narrative commentary

Six alternative designs and the T1 period approach have been examined for the boundary capability uncertainty mechanism to cover a cost uncertainty range of £497m – £1,038m in the T2 period, relative to a proposed baseline of £507m.

The designs reflect alternative ways to explain the cost to output relationship. These designs reflect lessons learned, stakeholder feedback, the T2 period uncertainty landscape and cost drivers. In the T1 period most of the designs where simple, with limited asset type distinction. This simplicity is part of the reason why costs did not track allowances effectively.

Consistent with all our volume driver UMs we have sought to strike a balance between complexity and accuracy (*cost reflective*). The alternative T2 period designs capture a range of factors, including whether geographic location is influential by examining designs which include boundary lengths; and whether creating separate UCA values for route (*i.e. projects with an associated km like reconducting*) and non-route projects helped to better explain the cost to output relationship.

Through the data examination for each design the benefits of converting data to the natural log domain were explored and in several of the designs we found benefit in doing this as it allowed us to better describe the relationship between costs and outputs. Appendix A.1 (*Our analytical techniques*) provides deeper commentary on our rationale for doing this and the accompanying Excel workbooks provide full coverage of the calculations performed.

Our data set showed no obvious examples of outlier data points. When relationships such as cost to MW, and cost to MWkm where examined we noticed observations were closely clustered with no outliers. The £ to km relationship also showed no obvious outliers; cost and route length follow a clearly linear relationship. This was beneficial in our UM design for new route projects. The accompanying Excel workbooks give a full illustration of the data relationships.

Unit costs have been used to derive expansion factors for cable circuits, both existing and new. In the T1 period an adjustment was made to our allowance for cable undergrounding costs using unit costs from a 2012 report by the IET. This reflects that the cost of undergrounding is a significant additional cost for network companies. In our assessment of designs for the T2 period we are proposing to simplify the approach by removing the undergrounding allowance and replacing this with a cable expansion factor. The main benefit of expansion factors over the approach used in the T1 period is that they allow cable projects and the lengths of existing cable circuits to feature in the regression analysis, without having to make ex-post adjustment. This is useful when factoring in the length of existing circuits crossing a boundary.

All models except for Model A and C significantly improve the mean difference between cost and allowance in comparison to the T1 period approach. The mean residual is over £120m if the T1 period method is followed; whereas it drops to below £10m if Models B, D, E, or F are selected. Standard deviation of the residual across a range of future scenarios is also lower in these four models; with the lowest standard deviation offered by Model F.

Since the means of Models B, D, E, and F are all close together, we prefer the model with the lowest standard deviation, Model F. This means the design has a near equal probability of costs being greater or less than allowance and the risk to consumers of large fluctuations is minimised.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
System need and best whole system solution uncertain. Requirements driven by annual ESO NOA process. Network company manages cost risk, whilst consumer best to manage volume risk.	Possibly annually, at least biennial with near 100% probability of some future requirement.	Minor increases in complexity of mechanism outweighed by significant increase in cost-reflectivity and mitigated through simplifications in other areas, such as approach to cable costs.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM7-2 Facilitating competition (pre-consents)	Chapter reference: 7	Volume driver

Proposal summary	**Onshore contestable projects** ▪ [redacted] £m/km for new onshore projects **Offshore contestable projects** ▪ [redacted] £m/km for new offshore projects **Additional details** ▪ Allowance is for all activities required to achieve planning consents ▪ Applies to projects meeting contestability criteria ▪ Extend Transmission Provisions for Wider Works (TPWW) to recover allowances spent if a project we are delivering terminates ▪ There will be no substitution of allowance between projects ▪ UM is symmetrical (*upside & downside*) with a £0m floor to prevent risk of negative allowances ▪ TPWW are automatic adjustment to the Annual Iteration Process with an ex-post review at end of price control to protect consumers ▪ TPWW extended to cover additional spend above UCA in event of efficient delays ▪ The forecast of funding in future periods needs to be sufficiently flexible to accommodate plan changes ▪ Spend in T2 period for output in future periods should be funded in the T2 period

Alternative options examined

- A percentage adjustor, which gives a fixed % of the total project costs as an additional allowance for delivering consents. The % is based on the mean % to achieve consents
- In-period determination of additional ex-ante funding required
- Allowed substitution of the fixed ex-ante baseline allowance between current and future projects (*the T1 period mechanism*)
- Fixed £m allowance for offshore projects

Results of analytical investigation

Onshore projects

Table 17 – Onshore project spend to consents and km

Project	Spend to consents (£m)	Route length (km)	£/km
Hinkley-Seabank	[redacted]	[redacted]	[redacted]
Canterbury-Richborough	[redacted]	[redacted]	[redacted]
Bramford-Twinstead	[redacted]	[redacted]	[redacted]
Horizon	[redacted]	[redacted]	[redacted]
Central Yorkshire	[redacted]	[redacted]	[redacted]
South Coast	[redacted]	[redacted]	[redacted]
Moorside	[redacted]	[redacted]	[redacted]
		Average excluding Moorside	[redacted]

The Moorside project has been excluded from this calculation. The project terminated in advance of a DCO application being submitted (unlike Horizon, for example, which also terminated but not till after the process was sufficiently advanced that a DCO application was made). For Hinkley costs for T-pylon development and Eakring test site removed from as these would be a one-off.

Offshore projects

Table 18 – Offshore projects spend to consents and km

Project	Spend to consents (£m)	km	£/km
Western Link	[redacted]	[redacted]	[redacted]
Eastern Link 1	[redacted]	[redacted]	[redacted]
Eastern Link 2	[redacted]	[redacted]	[redacted]
		Average	[redacted]

Data & assumptions

Table 19 – Facilitating competition (pre-consents) data and assumptions

[redacted] data points in total assessed.

Source of data	Note
Baseline connections	All projects listed as baseline feature in the underlying data set
Historical projects	Projects, additional to baseline sourced consistent with RRP
Assumptions	
▪ Only projects >£100m cost have been used in the analysis ▪ Costs are those incurred up to the point of achieving consents (*as opposed to pre-construction costs only*)	

Triggers of use

- Project receives a proceed decision from the NOA, or we receive a customer connection application

Narrative commentary

The purpose of the UCA is to provide an allowance to deliver a new output of a consented project ready for Late CATO and/or LOTI mechanism which could emerge in the T2 period and where we would be expected to obtain consents. In such cases we will develop the projects and deliver planning consents to facilitate competitive tender.

We have calculated the onshore UCA values by taking the mean of the spend to consents per km for six projects >£100m.

It should be noted that the spend to achieve used in our calculation of mean is the total spend to consents, including T1 period expense. Two of these projects, Central Yorkshire and South Coast require a T2 period baseline allowance to enable us to progress these to consents. Four projects are T1 period projects but, theoretically, if delivered in the T2 period would also meet the contestability criteria and be funded in this way. In any case, consideration of all projects is a more robust approach to calculating a unit cost allowance.

The offshore UCA value has been calculated by taking the mean of the spend to consents per km for three sub-sea HVDC projects.

Funding to achieve consents on both the Eastern Link projects is included within our baseline allowance proposal. It should be noted that the spend to achieve consents for these two projects is the total spend to consents, including any T1 period. We have also used actual costs for the Western Link project in this analysis, as the only sub-sea HVDC project that has been consented and delivered.

We believe in comparison to the alternative options examined, the proposed approach provides a fair and cost reflective method for allowing consenting activities to proceed whilst facilitating competition. It overcomes the T1 period mechanism limitations where no account for future uncertainty was provided and the automatic nature means projects can be progressed aligned with the signals provided by the ESO or to meet contractual obligations

with our customers, thus minimising consumer exposure to unnecessary constraint costs in the future. This would not interfere with Ofgem's requirement to undertake a specific need case review and project cost assessment, which is still intended where relevant under the proposed LOTI framework.		
Risk & ownership System need and approach to delivery of projects post-consents uncertain. Requirement driven by ESO NOA process and approach to CATO competition / Large Onshore Transmission Investment (LOTI). Network company manages cost risk, whilst consumer best to manage volume risk.	**Materiality & freq. of use** Estimated range of uncertainty of ~£300m based on inspection of potential projects in NOA. More than once in T2 period; linked to the ESO NOA process. High probability of change in future requirements, given T1 experience.	**Drawbacks & mitigations** Proposed approach flexible and robust to current understanding of approach to Late CATO and LOTI, but these have not yet been finalised leaving a minor risk of inconsistency. This risk can be mitigated through continued engagement in CATO and LOTI design.
Business Plan Data Table treatment No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.		

<table>
<tr><th colspan="2">UM8-1 Generation connections</th><th>Chapter reference: 8</th><th>Volume driver</th></tr>
<tr><td>Proposal summary</td><td colspan="3">Substation costs
▪ MW connected at new AIS substations: [redacted] £m/MW
▪ MW connected at existing AIS substations <100MW: [redacted] £m/MW
▪ MW connected at existing AIS substations >100MW: xxx £m/MW

▪ MW connected at new GIS substations: [redacted] £m/MW
▪ MW connected at existing GIS substations <100MW: [redacted] £m/MW
▪ MW connected at existing GIS substations >100MW: [redacted] £m/MW

Beyond substation circuit upgrade costs
▪ [redacted] £m/circuit km

New overhead line circuits
▪ [redacted] £m/circuit km

New underground cable circuits
▪ [redacted] £m/circuit km

Additional detail
▪ Continue with Transmission Provision Generation (TPG) in the event of project termination
▪ UM is symmetrical in application (i.e. allowance can be adjusted up or down by UCA) with a £0m floor, to prevent risk of negative allowances
▪ TPG are automatic adjustment to the Annual Iteration Process with an ex-post review at end of price control to protect consumers
▪ TPG extended to cover additional spend above UCA in event of efficient delays
▪ The forecast of funding in future periods needs to be sufficiently flexible to accommodate plan changes
▪ Spend in T2 period for output in future periods should be funded in the T2 period</td></tr>
<tr><td colspan="4">Alternative options examined

Seven different UM models, plus the updated T1 period model, for substation costs were assessed:

▪ T1 Model: UCA per MW of generation capacity connected (£/MW)
▪ Model A: Fixed UCAs for any generation connections split by new or existing substations and substation technology
▪ Model B: Fixed UCAs for any generation connection split by new or existing substations, plus additional UCAs per MW of generation capacity connected (£/MW) split by new or existing substations
▪ Model C: UCA per MW of generation capacity connected (£/MW)
▪ Model D: UCAs per MW of generation capacity connected (£/MW) split by connections above and below 100MW
▪ Model E: UCA per MW of generation capacity connected (£/MW) at new substations, plus UCAs per MW of generation capacity connected at existing substations (£/MW) split by connections above and below 100MW
▪ Model F: UCAs per MW of generation capacity connected (£/MW) split by new and existing substations and by substation technology
▪ Model G (proposed): UCAs per MW of generation capacity connected at new substations (£/MW) split by technology type, plus UCAs per MW of generation capacity connected at existing substations (£/MW) split by connections above and below 100MW and substation technology type

Stand-alone UCAs were also developed to accommodate instances where enhancement of existing circuits and when new overhead line circuits or new underground cable circuits would need to be built.

▪ UCA for Beyond Substation Works: £/circuit km
▪ UCA for New Overhead Line Works: £ / circuit km
▪ UCA for New Underground Cable Works: £ / circuit km</td></tr>
<tr><td colspan="4"></td></tr>
</table>

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Results of analytical investigation

These results represent the overall performance of each substation cost model (A-G) combined with individual UCAs for beyond substation works, new overhead lines, and new underground cables (*generally referred to as model A-G in the table below*). Please refer to the accompanying workbooks for a detailed description of these models, including the T1 period model which follows the approach taken in the T1 period.

Table 20 - Analytical performance of examined alternative generation connection UM models

Model	Mean (£m)	Standard Deviation (£m)
G – Proposed model	**0.78**	**22.98**
T1 method	-7.74	45.70
A	-7.24	40.89
B	-23.34	31.60
C	125.62	50.92
D	-15.85	45.94
E	5.97	24.77
F	152.48	38.52

Data & assumptions

Our dataset of [redacted] projects for analysis of generation connection UMs is drawn directly from our portfolio of contracted future connection projects.

Table 21 – Generartion data and assumptions

Data Source	Notes
Contracted projects	Future generation connection projects where a customer has applied for and accepted a connection offer. The scope and cost of works are specified in these contracted offers.
Assumptions	
▪ A snapshot of the contracted connections portfolio (*as per the TEC register*) was taken when analysis commenced. Projects that have since terminated have been excluded from our dataset ▪ Projects with connection dates in the T3 period have been included to increase the number of data points available. These projects are representative of potential T2 period connection types, when considering requirements to meet net-zero targets	

Triggers of use

- New applications from generation customers that are not part of our baseline plan

Narrative commentary

The T1 period mechanism was based on a simplistic calculation of average cost (*for substation works*) per MW of connected generation capacity ([redacted] £/kW). This was supported by separate UCAs for new overhead line and new cable works derived from a 2012 IET report.

A cost uncertainty range of £178m - £455m for generation connections is estimated across the T2 period. We have developed seven UM models (*plus the T1 period model*). The models examine cost drivers to accommodate newly emerging customer types and to increase cost reflectivity.

While the T1 mechanism worked broadly well across our portfolio, cost reflectivity for individual projects could be improved. The changing type of customer expected over the T2 period will mean that there is a less direct link between generation capacity and connection cost and hence refined versions of the T1 period approach are required to ensure UM performance across our expected connection portfolio is maintained.

To improve the cost reflectivity of the UM we categorise generation connection costs into four categories: Connecting Substation Costs, Beyond Substation Circuit Upgrade Works, New Overhead Line Works, and New Cable works. Our analysis identified the substation element of generation connection projects has the clearest set of cost drivers (*e.g. new or existing substation, substation technology, volume of generation capacity connected*). Costs for beyond substation circuit upgrade costs, new overhead line, and new cable works were considered consistent across all connections and a common £/circuit km rate for each category is proposed. These would be used in conjunction with any of the substation UM models.

The results shown in table 20 compares the overall performance of the substation cost UMs combined with the beyond substation works UCA, the new OHL UCA, and the new cable UCA.

Model A can be considered the most simplistic of the models assessed, providing a set of fixed allowances for generation projects based on the characteristics of the connecting substation and is totally independent of the size of connection being made. Performance of this model is broadly like the T1 period model. This is expected as both take a basic approach to identifying cost drivers.

Models C and D categorise projects above and below a connection capacity of 100MW. However, both models have a standard deviation greater than the T1 period model and hence offer no benefits.

Model F improves upon the T1 period standard deviation but has a mean far from zero indicating a poor balance of risk allocation and is therefore not preferred.

Model B further improves the standard deviation and has a mean moving towards zero, but relative to models E and F is further out.

Model G provides the best performance with a both the lowest standard deviation and mean closest to zero. Whilst, Model G is the most complex of the models proposed i.e. it categorises connection projects by substation type, substation technology, and by connection capacity. We believe it is implementable and is outweighed by the significant benefits of additional cost reflectivity.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Network company manages cost risk, whilst consumer best to manage volume risk.	At least annually, with near 100% probability of some future requirement.	Additions to the mechanism outweighed by significant increase in cost-reflectivity and mitigated through providing greater clarity on which assets the UCA is covering.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM8-2 Demand connections	Chapter reference: 8	Volume driver

Proposal summary	**Substation costs**
	Connection Projects
	▪ Capacity delivered at new substations:
	  o if each new transformer < 240MVA: [redacted] **£m/MVA**
	  o if each new transformer ≥ 240MVA: [redacted] **£m/MVA**
	▪ Capacity delivered at existing substations: [redacted] **£m/MVA**
	▪ Capacity delivered at new substation < 50MVA: [redacted] **£m/Transformer**
	
	Infrastructure Projects
	▪ New Transformer delivered: **xxx £m/Transformer**
	▪ No Transformer required: **£**[redacted] **(fixed)**
	
	New Circuits
	▪ Overhead lines ≥ 132kV: [redacted] **£m/circuit km**
	▪ Overhead lines = 33kV: [redacted] **£/circuit km**
	▪ Underground cable ≥ 132kV: [redacted] **£m/circuit km**
	▪ Underground cable = 33kV: [redacted] **£/circuit km**
	
	Additional detail
	▪ Continue with Transmission Provision Demand (TPD) in the event of project termination
	▪ UM is symmetrical in application (*i.e. allowance can be adjusted up or down by UCA*) with a £0m floor, to prevent risk of negative allowances
	▪ TPD are automatic adjustment to the Annual Iteration Process with an ex-post review at end of price control to protect consumers
	▪ TPD extended to cover additional spend above UCA in event of efficient delays
	▪ The forecast of funding in future periods needs to be sufficiently flexible to accommodate plan changes
	▪ Spend in T2 period for output in future periods should be funded in the T2 period

Alternative options examined

The commercial arrangements for demand connections are inherently complicated in nature. Demand customer projects are categorised into two types: 'Connection' projects and 'Infrastructure' projects. We have explored nine alternative design options for substation costs, of which seven are applicable to Connection projects (*representing most of our demand projects)* and two are applicable to Infrastructure projects.

Substation costs:

Connection Projects

- **Model A**: Fixed UCAs for any demand connections split by new or existing substations
- **Model B**: Fixed UCAs for any demand connection split by new or existing substations, plus additional fixed UCAs for each new substation bay delivered split by new or existing substations
- **Model C**: Fixed UCAs per new Transformer delivered split by new or existing substations
- **Model D**: Fixed UCA per new Transformer delivered
- **Model E**: UCA per MVA of new capacity delivered (£/MVA)
- **Model F**: UCAs per MVA of new capacity delivered (£/MVA) split by new or existing substations
- **Model G** (*Proposed*): UCA per MVA of new capacity delivered (£/MVA) at existing substations, plus UCAs per MVA of new capacity delivered (£/MVA) at new substations split by individual Transformer capacity

Infrastructure Projects

- **Model 1**: Fixed UCA per new Transformer delivered
- **Model 2**: £/MVA new capacity delivered

OHL, Cable & Small Capacity Connections:

Stand-alone UCAs were also developed to accommodate projects where either the capacity delivered is very low, no new capacity is required by the customer, and where new overhead lines would need to be built

Connection Projects where Capacity at new substation <50MVA: Fixed allowance per Transformer
Non-Transformer Infrastructure Projects: Fixed allowance per project
New Overhead Line Works ≥ 132kV: £ / circuit km
New Overhead Line Works = 33kV: £ / circuit km
New Underground Cable Works ≥ 132kV: £ / circuit km
New Underground Cable Works = 33kV: £ / circuit km

Results of analytical investigation

These results represent the overall performance of each substation cost model (A.1-G.2) combined with the individual UCAs for non-transformer infrastructure projects, new overhead lines, and new underground cables (*generally referred to as model A.1-G.2 in the table below*). The UCA for <50MVA projects applies only to substation cost models E.1, E.2, F.1, F.2, G.1, G.2. Please refer to the accompanying workbooks for a detailed description of these models, including the T1 model which follows the approach taken in the T1 period.

Table 22 – Analytical performance of examined alternative demand connection UM models

Model	Mean (£m)	Standard Deviation (£m)
G.1 – Proposed model	**0.92**	**11.89**
T1 Method	6.70	23.68
A.1	-4.40	11.71
A.2	-1.32	13.50
B.1	-10.82	18.36
B.2	-7.74	19.58
C.1	-5.20	11.73
C.2	-2.12	13.51
D.1	-5.69	22.14
D.2	-2.61	23.07
E.1	5.09	23.50
E.2	8.17	23.98
F.1	5.65	10.87
F.2	8.73	12.11
G.2	4.00	13.30

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Data & assumptions

Our dataset of [redacted] projects for analysis is drawn from contracted future connection projects and historical project delivered in the T1 period.

Table 23 - Demand data and assumptions

Data Source	Notes
Contracted projects	Future demand connection projects where a customer has applied for and accepted a connection offer. The scope and cost of works are specified in these contracted offers.
Historical projects	Demand connection projects that have been delivered or will be delivered in the T1 period.
Assumptions	
▪ Projects that represented cost outliers were excluded from our analysis – e.g. projects that involved the construction of a tunnel. These are unique features that have a significant impact on cost and are not anticipated to occur in the T2 period ▪ Also excluded are projects that required SGTs or new GSPs to be delivered for reasons other than DNO growth. For example, where the transmission network is re-configured and 'demand assets' must be delivered to maintain security of supply for a DNO. These projects can differ in scope from a 'standard' demand connection and hence are excluded. Taking down the DNO circuits on the Hinkley-Seabank route corridor and replacing with additional SGTs is an example of this	

Triggers of use

- New or updated applications for demand connections that are not part of our baseline plan

Narrative commentary

The T1 period UM took a one size fits all approach and did not differentiate between the different cost drivers. This approach resulted in cases of under-recovery of costs when delivering new substations. As the UM made no distinction between Infrastructure and Connection project types allowances for Infrastructure project were always lower than costs. At Infrastructure sites our price control arrangements must provide a far higher level of allowance to cover our costs than at Connection sites. This difference and its effect are explained fully in the accompanying Excel workbook.

Additionally, we are seeing a shift in customer types and location resulting in new substation, plus we are seeing smaller capacity connections requests. Further, we have observed cases where DNOs request connections for feeder circuits with no transformer capacity. These new customer types further exacerbate the weaknesses of the T1 period model.

Our modelled cost uncertainty range of £54m - £201m for demand connections in the T1 period.

We have tested several alternative UM models that examine the different cost drivers for demand projects. These balance complexity vs. accuracy and opportunities for innovation. As Connection projects are more common than Infrastructure projects most of our analysis dataset represents Connection projects. This allowed a range of cost drivers for these projects to be examined resulting in seven UM models being developed and assessed. A smaller available data set for Infrastructure projects meant only two UM models being developed for these projects.

UM models which measure output via transformer capacity (MVA) were found to be unsuitable for providing allowance for projects where only a small level of capacity is required (*e.g. rail connections*). To manage this a stand-alone UCA was proposed for projects where the capacity delivered by each new transformer was <50MVA. This stand-alone UCA would be used in conjunction with Models E, F, G only (*as other models are not based on capacity delivered*).

To accommodate projects where a demand customer may request a connection at an infrastructure site but no new SGT capacity *(e.g. to connect a feeder circuit*), a stand-alone fixed allowance was calculated.

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The results shown in table 22 compares the overall performance of the Connection UMs combined with the Infrastructure UM, the fixed allowance for non-SGT infrastructure projects, and the new OHL allowance.

Model G.1 is our proposed model. While models A.1, C.1, and F.1 offer a slightly improved standard deviation the mean of Model G.1 is significantly closer to zero and hence represents the best balance of risk between consumers and NGET in terms of potential T2 outcomes. The granularity of the G.1 model, offered through a tiered UCA for new substation projects by transformer capacity, allows this model to retain cost reflectivity across our range of potential connection types making this model robust against the changes that could occur in the demand customer space over the T2 period.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Network company manages cost risk, whilst consumer best to manage volume risk.	At least annually, with near 100% probability of some future requirement.	Additions to the mechanism outweighed by significant increase in cost-reflectivity and mitigated through providing greater clarity on which assets the UCA is covering.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM7-3 System operability (voltage)	Chapter reference: 7	Volume driver
Proposal summary	**Static Reactive Power Compensation** ▪ [redacted] MVAr reactive power capability delivered: [redacted] **£m/MVAr** ▪ [redacted] MVAr reactive power capability delivered: [redacted] **£m/MVAr** ▪ [redacted] MVAr reactive power capability delivered: [redacted] **£m/MVAr** **Dynamic Reactive Power Compensation** ▪ MVAr reactive power capability delivered: [redacted] £m/MVAr **Additional details** ▪ UM is symmetrical in application (i.e. allowance can be adjusted up or down by UCA) with a £0m floor, to prevent risk of negative allowances ▪ Transmission Provision Voltage (TPV) created to allow recovery of efficiently incurred spend on reactors as directed by the ESO which are subsequently delayed or cancelled ▪ TPV is automatic adjustment to the Annual Iteration Process with an ex-post review at end of price control to protect consumers ▪ The forecast of funding in future periods needs to be sufficiently flexible to accommodate plan changes ▪ Spend in T2 period for output in future periods should be funded in the T2 period	

Alternative options examined

The primary transmission investment option to manage high system voltage conditions is a shunt connected static reactor. Reactors can be installed at various voltage levels and with various ratings (MVAr).

Emerging system operability challenges, as highlighted by the ESO, may mean that dynamic reactive power compensation devices could sometimes offer a more effective whole system solution than the standard static reactor.

We have explored four options (*including our proposed model*) for reactive power compensation costs, of which three are applicable to static reactive compensation and one is applicable to dynamic reactive power compensation.

Static Reactive Power Compensation

- **Model A**: UCA per MVAr of new static compensation capability delivered, (£/MVAr) assessed through unit cost distribution analysis
- **Model B**: UCA per MVAr of new static compensation capability delivered (£/MVAr), split by connecting substation voltage, assessed through unit cost distribution analysis
- **Model C** (*preferred*): UCA per MVAr of new static compensation capability delivered (£/MVAr), split by level of compensation capability delivered, assessed through unit cost distribution analysis

Dynamic Reactive Power Compensation

- **Model 1** (*preferred*): UCA per MVAr of new dynamic compensation capability delivered (£/MVAr)

Due to the limited dataset available for dynamic reactive compensation, all alternative analytical approaches for dynamic reactive compensation were found to give identical UCAs and hence an output-based approach (£/MVAr) was preferred.

Results of analytical investigation

These results represent the overall performance of each Static reactive power compensation cost model combined with the single dynamic reactive compensation cost model (*generally referred to as model A-C in the table below*). Please refer to the accompanying workbooks for a detailed description of these models.

Table 24 - Analytical performance of examined alternative boundary capability UM models

Model	Mean (£m)	Standard Deviation (£m)
C – Proposed model	**0.6**	**1.9**
A	27.6	4.4
B	12.2	2.7

Data & assumptions

Our dataset of [redacted] projects for analysis is drawn from two sources – historical schemes delivered in the T1 period and our inputs to the ENA High Voltage case study project.

Table 25 – System operability data and assumptions

Data Source	Notes
Historical projects	Reactive compensation projects that have been delivered or will be delivered in the T1 period.
High Voltage case study inputs	We provided a range of future reactor investment options into the ENA High Voltage Case Study project. These options were developed to a level suitable for use in our UM development.
Assumptions	
▪ Projects that represented cost outliers were excluded from our analysis. These projects constituted cases where specific site conditions resulted in very high installations costs, which are not expected to occur in the T2 period	

Triggers of use

- Outcome of whole system assessment concluding that transmission reactive compensation offers the best solution for consumers, or other ESO/ customer signal as appropriate

Narrative commentary

Our T1 period framework included a baseline allowance for reactor investments but no UM to provide allowance for any additional projects. The management of system high voltage has become a significant issue over T1 period due to the changing nature of customer types and the decentralisation of generation. This has led to the ESO incurring increasing operational costs to keep system voltage within statutory limits.

All future energy scenarios forecast an increase in the factors that cause high system voltages and hence significant levels of compensation will be required to ensure the system remains compliant.

The emergence of whole system ways of working has increased the range of potential solutions to voltage management issues, including DNO investments and commercial services from generators. There is therefore uncertainty over both exact requirements. We have adopted a position of a low baseline to meet immediate ESO requirements supported by a UM. This approach was supported by stakeholders including DNOs and the ESO.

Dynamic reactive compensation can contribute to the mitigation of other system issues such as stability. There may be occasions when a whole system assessment concludes that the most efficient investment is one that can address multiple system issues at once. Therefore, our UM proposals includes a separate UCA to provide allowance for dynamic reactive compensation that is more expensive than standard static types.

We have assessed three output-based UM models for static reactors and investigated the relationship between cost and characteristics such as connection voltage and the capacity of reactive compensation delivered. We have used unit cost distribution analysis technique to assess the cost to output relationship.

As table 24 shows there is limited difference between the means and standard deviations of the models but one, model C is clearly the best performer with the lowest mean and narrowest standard deviation and is so preferred.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
System need and best whole system solution uncertain. Requirements driven by expanded annual ESO NOA process and System Operability Framework. Network company manages cost risk, whilst consumer best to manage volume risk.	Possibly annually, at least biennial. 100% probability of some change in future requirements.	UCA restricted to set unit sizes may restrict type of solution All system operability solutions are market tested by the ESO, or compared through the expanded NOA process, which mitigates any reduction in scope for innovation.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM8-3 Low voltage substation re-build	Chapter reference: 8	Volume driver

Proposal summary	**New substations** ▪ [redacted] £m/substation for each new substation required **Individual asset replacement** ▪ Allowance of items selected from menu when individual assets require replacing (*e.g. circuit breakers*) – see below for menu **Additional detail** ▪ Whole systems process undertaken before committing to spend

Alternative options examined

- Output based UCA examined when replacing individual assets, such e.g. £/MW and £/kA

Results of analytical investigation

Full substation replacement

Table 26- analysis of substation replacement costs

Site	£m/ substation
East Claydon 132kV substation	[redacted]
Willington 132kV substation	
Drax 132kV substation	
Fawley 132kV substation	
Average	

Individual component replacement (circuit breakers and associated assets)

Table 27 – menu of costs for circuit breaker replacement

Item	
Fixed costs: ▪ Bay refurbishment (full) ▪ Database changes ▪ Substation control system	[redacted] £m/substation
Bay - LV 132kV (AIS)	[redacted] £k/bay
Bay - LV 132kV (GIS)	£k/bay
Bay - LV 275kV (AIS)	£k/bay
Bay - LV 275kV (GIS)	£k/bay
Bay - HV 132kV (AIS)	£k/bay
Bay - HV 132kV (GIS)	£k/bay
Bay - HV 275kV (AIS)	£k/bay
Bay - HV 275kV (GIS)	£k/bay
Bay - HV 400kV (AIS)	£k/bay
Bay - HV 400kV (GIS)	£k/bay

Data & assumptions

Table 28 – low voltage substation re-build analysis data and assumptions

12 projects assessed.

Source of data	Note
NGET Internal	All projects sourced from internal cost analysis of works required.
Assumptions	
▪ Only selected substations where indicative analysis suggests upgrades to the TO assets would be required. These will be subject to a Whole System assessment during the T2 period	

Triggers of use

- Updated bilateral connection agreement from the DNO following whole system assessment

Narrative commentary

Embedded generation is forecast to grow 4% Compound Annual Growth Rate (**CAGR**) in the T2 period (*England & Wales Common Energy Scenario, though in reality it could be much higher as the scenario is not aligned with new net-zero by 2050 target)*, which can cause fault levels to rise at transmission substations.

The capability of circuit breakers to dissipate energy during a fault is limited. Replacing assets is safety critical if no alternative whole systems solutions can be found. Several site on the NGET transmission network are already close to maximum fault level limit, for example those sites in table 29. In total a cost uncertainty of ~£105m, calculated through examining the cost to replace assets at sites which have high fault levels and where indicative analysis of system conditions and available solutions indicate a transmission solution is required.

Table 29 - analysis of anticipated substation replacement details

	Common Energy Scenario			
	MW Increase (MW)	**Fault Increase (kA)**	**Site head room (kA)**	**Rationale for our anticipated expenditure**
Cardiff East	348.2	8.1	3	Already has a split running arrangement
Chesterfield	339	6.6	1.6	Already has a split running arrangement
Rainhill	276	6.3	0.3	Already has a split running arrangement
Upper Boat	244	5.5	5	8-mesh corner substation
Seabank	338	4.7	0.59	Already has a split running arrangement
East Claydon	64	0.2	0.0	Already has a split running arrangement – rebuilding to ensure all substation items, including civils can withstand the forecasted fault levels
Keadby	79	0.9	0.0	DNO is rebuilding its 132kV substation to allow additional EG to connect, NGET need to replace it's 3 CBs as part of this
Willington	64	0.7	0.4	Already has a split running arrangement. To meet future fault current requirements all components, need to be replaced
Penn	147	0.7	0.6	Already has a split running arrangement
Drax	16	0.1	0.1	Civil structures need to be replaced to meet forecasted fault currents
Fawley	78	0.5	0.3	An additional 3rd SGT is contracted to connect. this makes a split arrangement difficult.
West Melton	245	4.9	0.2	Already has a split running arrangement

Before we commit to replacing assets, we are committed to continuing our whole system review with relevant DNOs and the ESO to examine the trade-off between transmission, distribution and operability solutions to manage the issue. When a transmission network solution is identified as preferable, as signalled by updating the Bilateral Connection Agreement with the DNO, then having a UCA is appropriate to cover funding.

We believe that the approach proposed represents a sensible way forward to managing this area of uncertainty. Alternative approaches such as designing an output-based unit cost allowance when replacing individual assets, like circuit breakers was considered however we felt this could be disadvantageous for consumers as a £/MW or £/kA based on increasing volumes of connections of embedded generation could lead to allowance being paid without delivery of assets or too little allowance in some cases. The differential factor is the amount of fault level headroom at a substation which can vary from site-to-site.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Network company manages cost risk, whilst consumer best to manage volume risk.	Possibly annually, with near 100% probability of some future requirement.	Use of asset based UCA limits scope for potential innovation, although this is offset by further assessment of whole system solutions.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM7-4 Protection & Control	Chapter reference: 7	In-period determination

Proposal summary

- An in-period determination on additional investment requirements for protection and control equipment replacement and installation
- No other proposals include this

Alternative options examined

Table 30 – Alternative options to manage falling short circuit levels and inertia

	Quanta Technology recommendations	TO Cost (£m)
i.	Relay monitoring, setting review, and setting changes	[redacted]
ii.	Detailed modelling and coordination studies	[redacted]
iii.	Replacement of relays (*estimate*)	[redacted]
iv.	Implementation of a PMU system for protection (*estimate / option*)	[redacted]

- Option 1 - Do nothing [£0m]
- Option 2 (*preferred*) - Deliver recommendations (i) + (ii) in our baseline plan [£31.1m] & in-period determination for replacement costs
- Option 3 - Deliver recommendations (i) + (ii) + (iii) in our baseline plan [£[redacted]m]
- Option 4 - Deliver recommendations (ii) + (iv) in our baseline plan [£[redacted]m]

Data & assumptions

- A study commissioned through independent experts, Quanta Technology, and extensive international stakeholder engagement

Triggers of use

- Outcome of detailed modelling and coordination studies, and the review of asset settings

Narrative commentary

Power systems around the world are decarbonising and having to contend with the operability implications of increasing volumes of renewable generation connected to the network via power electronics. The Government's commitment to net-zero 2050 looks likely to accelerate this trend in the UK.

The reducing network Short Circuit Level (**SCL**) and inertia level, because of the increasing proportion of renewable generation and interconnectors, is a major risk to the safe and reliable operation of transmission protection and control systems. Failure to address this risk could expose consumers to a combination of an inability to achieve net-zero 2050, increased system operation costs because of needing to constrain on conventional plant and a higher likelihood of network disturbances arising from post fault instability, and the associated economic impacts.

We have been working closely with both domestic and international stakeholders in seeking to better understand and overcome the challenges. Work with the ESO and other TOs, through the System Operability Framework, indicates that this work must be undertaken in the T2 period to maintain confidence in a safe and reliable transmission network in England & Wales into the future. A study commissioned through independent experts, Quanta Technology, used available data to assess the impact of decreasing SCL and inertia on our network and made recommendations on the volume, scope and cost of approaches to mitigate likely impacts.

Several options for implementing Quanta's recommendations were considered. Option 2, involving (i) relay monitoring, setting reviews and setting changes alongside (ii) detailed modelling and coordination studies at a cost of £31.1m is our preferred option. These costs are highly certain, having been derived primarily from Quanta

Technology's independent assessment, checked against our procurement and commercial database and utilising previous experience on project management and site delivery.

Quanta's work indicates relay replacements will also be required (*at an estimated cost of £90.2m*), but we are proposing a within period determination for this work to manage uncertainty around volume, scope and cost. The outcome of the detailed modelling and coordination, as well as further engagement with stakeholders, will provide the necessary certainty.

Further detail can be found in annex A7.03 Protection and Control Coordination.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Specific mitigating investment required uncertain. Requirements driven by detailed study of system requirements, from modelling activity included in baseline plan. Cost and volume risk too high to set ex-ante allowances to protect consumers.	A total uncertainty of £90.2m is estimated based on independent review by Quanta Technology. Low frequency – upon outcome of coordination study. 100% probability of coordination studies identifying some additional future requirements.	A within period determination with a fixed date or window could delay funding to undertake the work required to operate a net-zero system by 2025 and mitigate the issues highlighted by the ESO in the System Operability Framework We propose that the determination could take place at any point during the T2 period when coordination studies have provided enough clarity on scope.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM7-5 Whole systems Co-ordinated adjustment mechanism	Chapter reference: 7	In-period determination
Proposal summary	▪ We support Ofgem's proposed Coordinated Adjustment Mechanism. We welcome the progress on this and will work through the detail of its operation through the draft and final determination stages of the RIIO-2 submission, as well as engaging through the ongoing work that will be required to ensure necessary consistency between sectors, especially electricity distribution	

Alternative options examined

N/A

Data & assumptions

N/A

Triggers of use

- NOA and/or specific collaboration with the DNO and ESO in system design

Narrative commentary

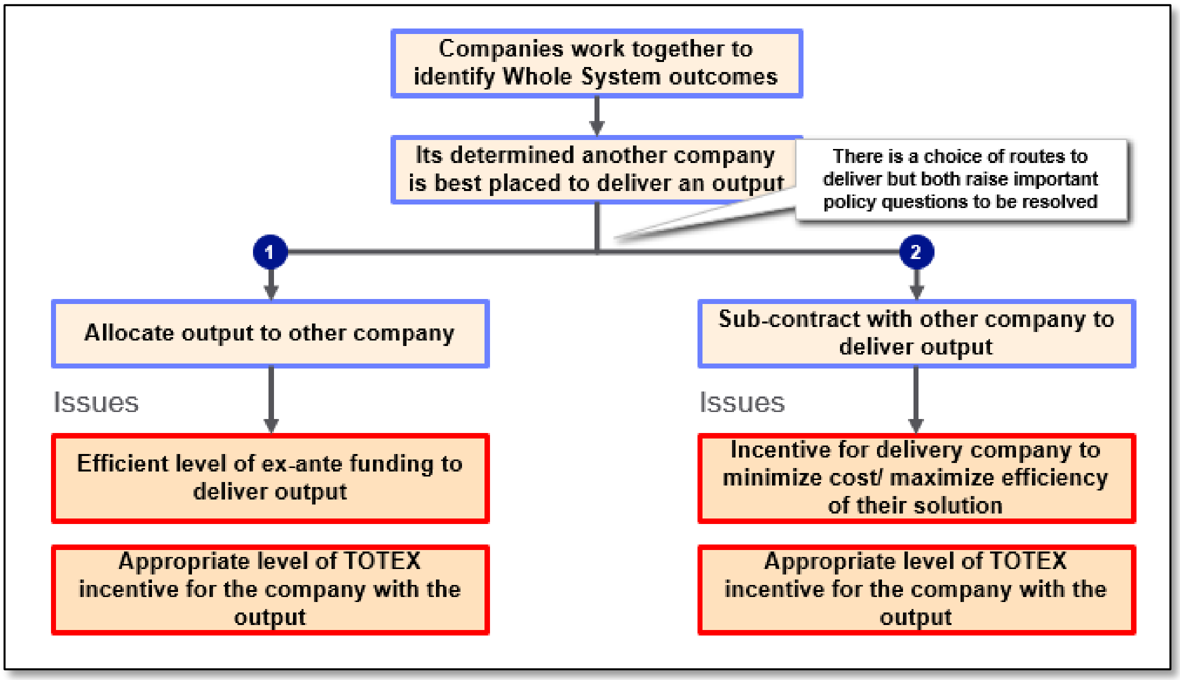
In many cases a central outcome from identifying whole system solutions will be a requirement to transfer either an output or funding between network companies. We believe that the uncertainty mechanisms are the most efficient and simplest vehicle to allow for this exchange. If they are designed to be complementary, and where appropriate mirrored between network companies they will provide an efficient tool to flex the delivery of outputs by a network company, where processes such as the NOA and Regional Development Plans (**RDPs**) have identified new efficiencies compared to the baseline plan. Further, the uncertainty mechanisms can also act as an efficient tool for transferring allowances when network companies have agreed bilaterally to exchange outputs, in the instance another party is better placed to deliver, and the consumer benefits can be demonstrated to Ofgem.

In some instances, however the design of uncertainty mechanisms covering specific assets is not practical or appropriate for some network companies at the outset of a price control, whilst it might be for others. In these cases, an efficient tool is required to allow exchange of allowances, so that whole system solutions which benefit consumers can still be delivered.

From our examination of the most recent proposals for the Coordinated Adjustment Mechanism, as outlined in the *RIIO-2 Sector Specific Methodology Decision (May 2019)* we feel many of the salient points that need addressing for it to work have been identified, chiefly: (1) the trigger threshold; (2) the timeliness of its use in the price control period; (3) eligible projects; and (4) incentivisation of its use. Important further detail is required on the mechanics of its operation, especially on how the allowances will be exchanged between companies.

At present, we have identified two potential routes for network company delivering an output to transfer to another network company: (1) Allocate the output to the other company; or (2) subcontract with the other company to deliver. Both routes present incentivisation issues that need to be resolved, as summarised in figure 13.

Figure 13 - Approach to reconciling a whole system solution delivered by one network company for another



The Coordinated Adjustment Mechanism is likely to be best suited to route (1), although we note that further detail will be required on how funding levels at the respective companies will be adjusted and the setting of the appropriate level of TotEx incentive for the company with the output.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Network company manages cost risk, whilst consumer best to manage volume risk.	Possibly annually, with near 100% probability of some future requirement.	Implementation may require further updates to system codes. The mechanism will also require agreement with the DNOs who lag the TOs in timing of price controls. We will continue to work with Ofgem and industry in parallel to our price control submission to implement.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM7-6 Harmonic coordination	Chapter reference: 7	In-period determination
Proposal summary	▪ An in-period determination to allow NGET to coordinate harmonic design, and build cheaper harmonic filters following agreement with our customers ▪ For the T2 NGET-led approach would require expenditure between £60m-£100m	

Alternative options examined

- Including within the baseline proposal

Data & assumptions

- For the period up to 2030, a customer-led approach would require approximately [redacted] harmonic filters to be installed, at an estimated whole life cost of £146m
- A TO led approach would require [redacted] filters to be installed (i.e. fewer units), at an estimated whole life cost of £119m. This would be a consumer saving of £27m (18%)
- For the T2 period the TO expenditure is between £60m-£100m

Triggers of use

- Signed Bilateral Connection Agreement with customer

Narrative commentary

Customers are currently required to install harmonic filters to comply with voltage levels set in the Grid Code (a customer-led approach). Uncontrolled harmonics in the power system can have negative effects such as overheating of generators, motors, transformers, cables and capacitors, maloperation of protection equipment and circuit breakers, metering giving false readings, and interference with telecommunications and signalling systems. Harmonics can lead to reduced equipment life. Operationally, they can lead to inadvertent tripping of equipment.

The Grid Code places an obligation on transmission network owners to ensure that harmonic levels on the network are managed and kept below 'acceptable' levels as defined in Engineering Recommendation G5/4. In turn, network owners discharge this obligation by imposing harmonic limits on individual customers whose equipment creates harmonics. Customers are required to comply and stay within harmonic limits issued to them by network owners and consider ways to reduce or mitigate if they can't stay within the limits. Mitigation is usually achieved by installing harmonic filters.

The management of harmonics is an industry wide issue, as it is primarily driven by low carbon, electronic-based technologies such as solar PV, battery connections, EV charging, wind, HVDC connections etc. The proposal for TOs to take greater responsibility for installation and ownership of harmonic filters has been developed with other network owner customer support.

Once this is sufficiently advanced, we believe funding for harmonic filters should be managed via a price control in-period determination.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Customer need and timing of implementation uncertain. Requirements driven by volume of generation connected through power electronics (predominately renewables). Cost and volume risk too high to set ex-ante allowances to protect consumers.	Low frequency over T2 period (2 or 3 maximum anticipated). High probability of usage, subject to any necessary code changes being implemented.	Additional regulatory burden of in period determination outweighed by the consumer benefits Further mitigated by grouping of relevant customer projects informed by outcome of CfD rounds.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

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UM7-7 System operability (other ESO requirements)	Chapter reference: 7	In-period determination
Proposal summary	▪ An in-period determination, to provide allowances where an ESO whole system assessment (*or other ESO assessment)* of system operability requirements (*other than voltage*), indicate a transmission network solution is best for consumers ▪ Where the ESO's assessment determines a requirement for transmission-based system stability solution, e.g. a Synchronous Condenser we propose an in-period determination ▪ In-period determinations following ESO trigger of TO solution to manage System operability issues for investments >£20m ▪ Automatic allowance adjustment and logging up for investments <£20m	

Alternative options examined

N/A

Data & assumptions

N/A

Triggers of use

- Completion of an ESO led whole system assessment (*or other ESO process*)

Narrative commentary

The energy system is transitioning to one with increased volumes of non-synchronous generation and in April 2019 the ESO announced its ambition to be able to fully operate the electricity system with zero carbon by 2025.

We believe that network companies have a vital role to play, alongside traditional 'market' players in ensuring the ESO has the systems, services and products needed to minimise the cost of the transition for consumers. This can only occur if we have a flexible price control to deliver the required investment.

The ESO's System Operability Framework points to a range of system operability challenges, such as lower system inertia. TOs have already been delivering solutions in collaboration with the ESO to provide solutions to issues, such as Scottish Power Transmission's Project Phoenix (https://www.spenergynetworks.co.uk/pages/phoenix.aspx) to install a Hybrid-Synchronous Condenser on their network. Further, the ESO have instigated several NOA Pathfinder projects across the country to look for optimal solutions to a range of issues.

We believe it's prudent that we can bring forward solutions to operability challenges during the T2 period as inputs to the ESO's whole system assessments on a range of issues. The solutions likely to be required include, synchronous compensators to manage system stability issues, additional circuit breakers on the network to reduce system operational costs and inter-trips. If no funding mechanism is in place, we will not be able to deliver solutions that minimise cost.

Providing the ability to have an in-period determination means:

- Reduced system operation costs as the ESO
- Maintaining a reliable electricity supply – ensuring that protection and control systems work and the ESO can continue to operate the network in a safe and reliable manner
- Enabling net-zero by 2050 by allowing more renewables to connect to the system and displace conventional generation by not having any running restrictions

Where the ESO's assessment determines a requirement for transmission-based system stability solution, e.g. a Synchronous Condenser we propose an in-period determination. For all other ESO triggered solutions, e.g. inter-trips and additional circuit breakers we propose the TO be allowed to automatically increase revenue upon clear signal from the ESO. Revenue increases beyond £20m linked to this UM over the course of the T2 period would be subject to an in-period determination.

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Risk & ownership Volume of TO solutions to future operability challenges unclear prior to ESO whole system assessment. Risk too high to set ex-ante allowances.	**Materiality & freq. of use** High frequency for small requirements (*e.g. inter-trips*) Low frequency for large requirements (*e.g. synch. Comp.*) Very high probability of usage (*based on ESO's System Operability Framework*)	**Drawbacks & mitigations** Depending on how ESO requirements evolve over the T2 period, the frequency of usage for this mechanism could be quite high We propose to mitigate this through the introduction of a logging up mechanism for smaller requirements that the ESO has tested as economic.
Business Plan Data Table treatment No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.		

UM10-1 Extreme weather	Chapter reference: 10	In-period determination
Proposal summary	▪ One in-period determination within the T2 period, mid-way ▪ Account for changes to Engineering Technical Report (**ETR138**) guidance on flooding, and/ or direction from BEIS to protect sites from flooding ▪ Common in-period determination for all network companies following ETR138 guidance	

Alternative options examined

N/A

Data & assumptions

- No current view of cost associated with this uncertainty within T2 period

Triggers of use

- Changes to requirements for flood protection under ETR138 and/or direction from BEIS

Narrative commentary

Whilst flood risk does not tend to change significantly within short amounts of time, the recommended resilience against flooding has changed over T1 period requiring additional expenditure in this area. BEIS and industry regularly review ETR138 guidance and appropriateness. Whilst probability of using this reopener is low, having a UM would allow for flexibility in plans to adapt to latest threat guidance changes.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Neither network company nor consumer best placed to manage uncertainty.	One determination mid-way through the T2 period.	If threat levels rapidly change, it can result in expenditure on assets prior to triggering allowance. We will continue engagement with the relevant bodies to minimise this risk.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM10-2 Physical security	Chapter reference: 10	In-period determination
Proposal summary	- Two in-period determinations within the T2 period, mid-way, and at the end - Account for changes to Physical Security Upgrade Programme (**PSUP**) requirements within T2 period - Common determination proposed by Ofgem for all network companies governed by PSUP requirements	

Alternative options examined

- Ofgem confirmed proposal for in-period determination in T2 period

Data & assumptions

- There is currently no expectation that these in-period determinations will be used and therefore no expected cost of uncertainty

Triggers of use

- Changes to PSUP requirements made by CPNI or BEIS

Narrative commentary

Ofgem have proposed the use of two in-period determinations in the T2 period to account for changes in PSUP requirements. Determinations would allow for a positive or negative adjustment to allowances in response to changes to requirements for physical security.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Neither network company nor consumer best placed to manage uncertainty.	Two determinations proposed for T2 period. No significant changes expected.	If PSUP list changes, it can result in expenditure on security assets prior to triggering allowance. We will continue engagement with relevant to minimise this risk.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM10-4 OT Cyber Security	Chapter reference: 10	In-period determination

Proposal summary

- Two in-period determinations within the T2 period, mid-way, and at the end
- These plans would cover changing threat levels and available solutions
- Our expected uncertainty is approximately £[redacted]m

Alternative options examined

- Ofgem confirmed proposal for an in-period determination in T2 period

Data & assumptions

- **Data** – our estimate value of uncertainty has been calculated based on current expected expenditure for projects. This estimate is subject to change following delivery of T1 period investments and continued assessment of cyber threats, risks and available solutions

- **Assumptions** – Our main assumption for the T2 period is that Ofgem accept that flexibility is required for our cyber plans. We expect the cyber threat to change ahead of and throughout the T2 period and therefore we must be flexible in our approach to addressing cyber risk. As well as changes to cyber threats, new solutions will become available as technology matures. By taking advantage of new solutions, we will be able to better protect from cyber threats in the future

Triggers of use

- Changes to cyber threat, formal requirements, available solutions and capabilities

Narrative commentary

Cyber threats are constantly changing and the threat to Operational Technology is quickly advancing. We are responding, however expect these threats to change within the T2 period. As the landscape changes, solutions and capabilities also get more advanced and therefore may be more appropriate in the future. Allowing flexibility in our plans lets us address threats as they arise and allows us to take advantage of new solutions that may not have been previously available.

We understand that it may be Ofgem's intention only to allow the first in-period determination for OT if network companies chose not to submit their business plans in December 2019. Given the evolving landscape on OT, we have provided a proposal for investments in which we have high confidence in scope, cost and deliverability with a view of required projects for which we are not currently seeking allowances.

The work we are completing to enhance OT cyber resilience within the T1 period will enable us to be in a more informed position at the first T2 period in-period determination opportunity to request allowances. We therefore request that Ofgem allow network companies that have provided business plans in December 2019 to have use of the first in-period determination in T2 period.

We commit to ongoing engagement with the NIS Competent Authority informing Ofgem's decision of our proposed adjustment to allowances within T2 period.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Neither network company nor consumer best placed to manage uncertainty.	Two determinations currently proposed. Current estimate of materiality is £[redacted]m.	If threat levels rapidly change, it can result in expenditure on assets prior to allowance being triggered. We will continue engagement with the relevant bodies to minimise this risk.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

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UM10-3 IT Cyber Security	Chapter reference: 10	In-period determination
Proposal summary	▪ Two in-period determinations within the T2 period, mid-way, and at the end ▪ These plans would cover changing threat levels and available solutions ▪ Our expected uncertainty included within our plans is approximately £[redacted]m	

Alternative options examined

- Ofgem confirmed proposal for an in-period determination in T2 period (*aligned to those allowed for OT Cyber Security*)

Data & assumptions

- **Data** – our estimate value of uncertainty has been calculated based on current expected expenditure for projects. This estimate is subject to change following delivery of T1 period investments and continued assessment of cyber threats, risks and available solutions

- **Assumptions** – Our main assumption for the T2 period is that Ofgem accept that flexibility is required for our cyber plans. We expect the cyber threat to change ahead of and throughout the T2 period and therefore we must be flexible in our approach to addressing cyber risk. As well as changes to cyber threats, new solutions will become available as the landscape matures. By taking advantage of new solutions, we will be able to better protect from cyber threats in the future

Triggers of use

- Changes to cyber threat, formal requirements, available solutions and capabilities

Narrative commentary

Cyber threats are constantly changing and the threat to Operational Technology is quickly advancing. We are responding, however expect these threats to change within the T2 period. As the landscape changes, solutions and capabilities also get more advanced and therefore may be more appropriate in the future. Allowing flexibility in our plans lets us address threats as they arise and allows us to take advantage of new solutions that may not have been previously available.

Within their Sector Specific Methodology Decision, Ofgem stated that there would be two in-period determinations for works included within the Cyber Resilience Plan (*for OT works*) and one in-period determination for works included within the Business IT Security Plan (*for IT works*). The threats we face are constantly evolving and our IT systems can provide a gateway to our OT systems. For this reason, we consider it appropriate and would request Ofgem to also allow for a second in-period determination for the uncertainty within our Business IT Security Plan in T2 period.

We commit to ongoing engagement with the NIS Competent Authority informing Ofgem's decision of our proposed adjustment to allowances within the T2 period.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Neither network company nor consumer best placed to manage uncertainty.	Two determinations currently proposed. Current estimate of materiality is £[redacted]m.	If threat levels rapidly change, it can result in expenditure on assets prior to allowance being triggered. We will continue engagement with the relevant bodies to minimise this risk.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

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UM10-5 Black Start	Chapter reference: 10	In-period determination
Proposal summary	▪ One determination proposed in T2 period to update our plans to implementation the new Black Start standard currently under review by BEIS ▪ Common determination available for all network companies required to meet BEIS Black Start standard	

Alternative options examined

N/A

Data & assumptions

- No current view of cost uncertainty

Triggers of use

- Updated Black Start standard proposed by BEIS

Narrative commentary

BEIS are currently in the process of proposing a new standard for restoration times in the event of a Black Start scenario. To meet this standard NGET and other network companies would need to ensure that they can facilitate required restoration times and therefore invest in asset quality and capabilities.

We support the introduction of this standard, which has been reviewed by the Black Start Task Group. We propose the use of an in-period determination to account for the changes required to our plan because of the standard being implemented.

The benefit of allowing this flexibility to our plans would be that we can help to ensure achievement of BEIS's Black Start standard, facilitating faster restoration times in the event of a Black Start scenario.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Neither network company nor consumer best placed to manage uncertainty.	One in-period determination to adjust allowances	If risk levels rapidly change, it can result in expenditure on assets prior to triggering an allowance. We will continue engagement with the relevant bodies to minimise this risk.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM10-6 Ensuring a resilient network	Chapter reference: 10	In-period determination
Proposal summary	▪ Proposed in-period determination to account for new requirements to ensure a resilient network	

Alternative options examined

- No alternate options examined – determination selected due to low-medium chance of usage and meeting materiality threshold

Data & assumptions

- No current view of cost uncertainty

Triggers of use

- A new requirement to protect from threats that are not covered in any other UM or investment areas to implement a level of network resilience agreed amongst network companies and Ofgem

Narrative commentary

With the growing business and societal reliance on electricity, we must only ensure we are addressing and protecting the network from existing threats, we must deliver a network that provides future resilience beyond the T2 period.

We continue to engage with our stakeholders via established industry forums on the topic of resilience. This includes the CIGRE Power Systems Resilience Group who have aligned activities that are creating a positive collective momentum for a fresh look at future electricity sector resilience. The messages we are hearing from our stakeholders highlight a number of challenges in determining appropriate levels of resilience for the future. These challenges include increasing electricity demand, electricity dependency and societal expectation, increasing cross sector dependence, a changing energy landscape and emerging external threats. During the T2 period, we must continue to develop future resilience definitions, measures, metrics and/or principles for our business, the sector and, due to the increasing dependence on electricity, other interdependent sectors for beyond T2 period. We believe that this can only be achieved through strong collaboration with stakeholders, our industry and other sectors to agree a consistent view of the level of network resilience required and develop measures and solutions that can assure long-term resilience.

Threats can change quickly, and we must be flexible in how we adapt. Through our ongoing engagement with stakeholders on building a network resilient to threats, we want to be able to be flexible with our plans and consider new guidance or requirements on the topic of network resilience. There is currently no estimate of cost associated with this uncertainty.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
Neither network company nor consumer best placed to manage uncertainty	Low to medium chance of using reopener within T2 period.	If risk levels rapidly change, it can result in expenditure on assets prior to triggering an allowance. We will continue engagement with the relevant bodies to minimise this risk.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM11-1 SF_6 replacement programme	Chapter reference: 11	In-period determination
Proposal summary	▪ Allow for investment needed for SF_6 reduction	

Alternative options examined

- No SF_6 reduction investment programme in the T2 period
- Baseline funding for an SF_6 reduction investment programme

Data & assumptions

- We carried out an extensive review of our SF_6 assets and options for replacing them

Triggers of use

- To be developed

Narrative commentary

The UK's net zero by 2050 ambition became law in the UK in June 2019, which we fully support. SF_6 is our largest controllable greenhouse gas contributor and we recognise that achieving net zero needs a step change to how we manage our SF_6 equipment.

We are considering a mechanism to give flexibility to:

1) Respond to changing leaks within T2 period;
2) Assess the best intervention for the asset and leak and;
3) Stretch beyond the Science Based Target (SBT) Net Zero pathway.

This uncertainty mechanism will fund us to make reductions in SF_6 emissions with the long-term aim for continued and permanent reduction that our stakeholders expect to see from us.

Our stakeholders are clear that they want us to be carbon neutral faster than the 2050 target. During our consumer research testing 60% of consumers wanted us to be a net zero business by 2030 or 2040, instead of 2050. In line with our stakeholders, we believe it is the right thing to do, whilst ensuring the right levels of speed and cost are fully acceptable to consumers. Additionally, Ofgem asked that we provide information on what is needed to remove SF_6 from our system and whether it is carbon price sensitive. These investments are carbon price sensitive and the cost of carbon doesn't currently cover the investments required for this mechanism, which focuses on longer-term benefits.

Our considered for a mechanism has two levels of operation:

1) For reductions in SF_6 emissions up to our SBT net zero pathway in the T2 period, we're considering an approach that will build a value of SF_6 leakage reduction (or prevented) in £/(kg.yr). Our October proposal outlined a value of £150m to replace some of the worst leaking and simple Gas Insulated Busbar (GIB) assets on the system. Our considered approach would use a portfolio of solutions (repairs and replacement) using an annualised equivalent costing (AEC) which assesses the remaining life of the leaking assets to make the best decision for the installation, for example a repair to align with substation replacement. For level 1, the uncertainty mechanism funding in £/kg.year would be based on the value delivered and expected period of effectiveness (life of the intervention). This rate will need to be defined through engagement with Ofgem ahead of commencing the T2 period

2) For reductions in SF_6 emissions beyond the SBT net zero pathway in the T2 period, we think an extension to the level 1 approach could be suitable. The level 2 part of the uncertainty mechanism recognises the step change in performance required to respond to evolving environmental ambitions and allows us to go beyond the SBT net zero pathway for this period (-34% emissions by 2026). Level 2 could work in the same way as level 1 but with a re-calibrated for the funding rate in £/(kg.yr), because in level 1 the simplest assets with the highest leak rate will have already been targeted. Thus, the remaining assets will be more complex,

and the volumes of leaks will be smaller, requiring us to spend more to get the same benefit. We expect increments within level 2 meaning a non-linear approach would be required

The assets we are targeting with this UM in both levels aren't prioritised by existing processes, so there is limited overlap with our existing NARMs plans but they are complimentary to each other. We will engage with Ofgem and consumers to fully develop this approach over the coming months, aiming to have both parts of the mechanism in place for the start of the T2 period in 2021.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
The considered option allows to reflect the latest carbon price or requirements from stakeholders. We are best placed to manage this risk by developing a mechanism before the start of T2 period which does this.	We propose this determination would throughout the T2 period.	The net zero target is relatively recent. This UM allows us to develop a mechanism as details become clear.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

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UM11-2 Visual Impact Provision	Chapter reference: 11	In-period determination

Proposal summary	
	▪ An in-period determination to allow for the investment needed to take forward VIP projects once we have fully developed our proposals and Ofgem has reviewed them

Alternative options examined

- Baseline funding for our VIP projects.
- A true-up mechanism at the end of the T2 period

Data & assumptions

- We reviewed our experience with VIP projects in the T1 period, including the extent of stakeholder engagement and development time needed to produce firm proposals

Triggers of use

- The trigger for this UM is Ofgem approving the efficient costs of VIP projects that we have submitted

Narrative commentary

We have an established assessment methodology for VIP project priorities, created by an independent landscape specialist, which we have consulted on and which Ofgem has approved. There is strong support from local stakeholder groups to take forward VIP projects. With respect to VIP costs, most bill payers (66%) find it acceptable for the cost of VIP to be socialised via household bills.

We considered alternative such as baseline funding for our VIP projects. However, our experience with VIP projects in the T1 period is that we need to carry out extensive stakeholder engagement and development work to produce firm proposals that we can submit to Ofgem for approval. As a result, there can be long time lags between proposing a project and receiving funding approval. Ofgem assesses the efficient costs of VIP projects when we propose them, so an in-period determination appears to be a better approach than baseline funding.

We also considered a possible true-up mechanism at the end of the T2 period. However, this would involve us having to start projects without funding in place and with some uncertainty over when and what amount of funding we would receive. This would to slow down VIP projects which is not in the best interests of consumers.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
We develop our VIP schemes in close collaboration with stakeholders and Ofgem assesses the efficient	We propose this in-period determination would apply in the T2 period for each VIP scheme that we submit and which Ofgem approves	In-period determinations can create uncertainty, but there are clear and established rules around how VIP scheme are assessed and funded

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM11-3 Urban Impact Provision	Chapter reference: 11	In-period determination
Proposal summary	▪ A in-period determination to allow for the investment of up to £50m of consumer-funded budget to improve our assets or public spaces, focused on the top 30% most deprived urban areas in England and Wales	

Alternative options examined

- No funding for an urban improvement provision in the T2 period
- Baseline funding for an urban improvement provision in the T2 period

Data & assumptions

- We drew on our stakeholder feedback and stakeholder group comments as well as the information we have collected from our community work in the T1 period e.g. our community grants programme

Triggers of use

- A stakeholder-led panel will make awards based on proposals, focused on the top 30% most deprived urban areas, measured by the Index of Multiple Deprivation (IMD).

Narrative commentary

This in-period determination reflects feedback from our stakeholders that, in addition to the VIP scheme, we should have a scheme to improve our assets or public space in deprived communities. This approach has received excellent support from consumers in our acceptability testing workshops on the assumption that impacted stakeholders select the projects to be completed and Ofgem approves the efficient costs of the projects. For this reason, we ruled out not funding for an urban improvement provision.

We considered alternative baseline funding for an urban improvement provision. However, we thought it would be better to have a stakeholder-led approach to awarding funds for the urban improvement provision because some of our stakeholders have greater knowledge of the best ways to benefit urban deprived areas. We also thought it would be better for the funding to be released during the period to reflect changing community priorities. For these reasons. We will liaise with the Scottish TOs to assess whether this provision would also be relevant in Scotland.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
The stakeholder-led panel and Ofgem review of costs will make sure these schemes deliver net benefits	We propose this in-period determination releases funds for approved projects each year	In -period determinations can create uncertainty, but we are proposing a clear process for approving funds to be released

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM11-4 Net zero	Chapter reference: 11	In-period determination
Proposal summary	▪ In-period determination to allow for any investment needed in response to potential new requirements to achieve the UK's target of net-zero greenhouse gas emissions by 2050	

Alternative options examined

- **No net-zero in-period determination and no baseline funding**. We dismissed this option on the basis that the UK target of net-zero greenhouse gases by 2050 was only passed into law in June 2019 and there might be new requirements for energy network companies in the T2 period as the government develops it policy to achieve the target in more detail

- **No net-zero reopener, but baseline funding for a net-zero investment programme**. We are required to build our business plan based on the low end of the Common Energy Scenario and its assumptions about generation and demand. The scenario does not assume a reduction in greenhouse gases large enough to deliver against the UK's commitment to net zero by 2050. As a result, we could not include investment for a net-zero investment programme in our baseline. We also consider that the pathway to net-zero is currently too uncertain for us to be able to propose a full net-zero investment programme at this stage

Data & assumptions

We have made the following assumptions:

- There might be new requirements for energy network companies in the T2 period as the government develops it policy in more detail to achieve the net-zero bv 2050 target
- Given the need for rapid action to tackle climate change we do not think it is feasible to wait for the T3 period to start implementing any new net-zero requirements

Triggers of use

- A new requirement from the government or a governmental body in relation to achieving the UK's target of net-zero greenhouse gas emissions by 2050

Narrative commentary

The UK's commitment to achieve net-zero greenhouse gas emissions by 2050 was passed into law in June 2019.

Our business plan covers a crucial period when we all expect rapid change in the energy system to dramatically reduce carbon emissions to achieve the UK's net-zero by 2050 target. Our plan highlights specific opportunities within the regulatory framework, to enable and accelerate the UK's progress to net zero. We are putting forward collaborative, innovative, and whole-system solutions to support policymakers. We are reinforcing this with commitments to reduce our own emissions to deliver the UK's net-zero target and ensure no one is left behind in the energy transition.

There could be new net-zero requirements on energy network companies in the T2 period because the UK's target was only put into law in June 2019 and there remains a lot of uncertainty in government and the energy sector about the best pathway to achieve it. As the UK government starts to define its policy for low-carbon energy, heating and transport (and other sectors) in more detail there might be new requirements for energy network companies. This UM would allow for the investment that is required to happen more quickly.

We are proposing anticipatory options to help achieve the net-zero target, such as a rapid electric vehicle charging network at motorway service areas and reducing connection costs for off-shore wind generators. Projects such as these will need funding and our net-zero UM could provide a route to release these funds.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
The in-period determination deals with the risk that new net-zero	We propose this in-period determination would apply twice	Re-opening the price review can create uncertainty, but we are

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requirements arrive in the T2 period.	within the T2 period (*at the start and mid-way*).	limiting this UM to twice in the period and linking it to the specific trigger of new government requirements on net zero.

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.

UM12-1 Innovation plan	Chapter reference: 12	In-period determination
Proposal summary	▪ An in-period determination to allow us to reshape our innovation programme in 2022 to reflect the latest developments in decarbonisation and to make sure our innovation programme continues to meet the needs of all our stakeholders	

Alternative options examined

- No in-period determination

Data & assumptions

N/A

Triggers of use

- The trigger for this UM is in 2022 when will be able to update our T2 period innovation programme aligned with our stakeholders' views on the latest developments energy system

Narrative commentary

Our stakeholders want us to focus our innovation on the wider societal priorities of clean energy, driving down current and future consumer costs and opportunities for digitisation as well as the integration of the whole energy system and clean energy solutions for other sectors. These are areas where the energy system is continuing to change rapidly.

We considered not having a reopener, but this would mean we would have to set our innovation priorities based on our stakeholders' views at the end of 2019 and would not be able to update them for the changing energy system and the changing views of our stakeholders.

The benefit of this UM for consumers is that will enable us to revisit our innovation programme at the beginning of the T2 period to make sure it reflects the latest energy market developments and continues to meet the needs of all our stakeholders.

Risk & ownership	Materiality & freq. of use	Drawbacks & mitigations
The in-period determination avoids the risk that we are tied to delivering innovation projects we've developed with our stakeholders in 2019 that have become less beneficial to consumers than other projects	We propose this in-period determination would apply once in the T2 period in 2022	In-period determinations can create uncertainty, but we are limiting this determination to once in the period with a very specific purpose

Business Plan Data Table treatment

No uncertain costs included in the baseline plan; UM snapshot table (NGET_ET_12A_Uncertainty Mechanisms Snapshot table) and bespoke uncertainty tables (Table D.5.18) include our proposals.